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**E21B 43/10**

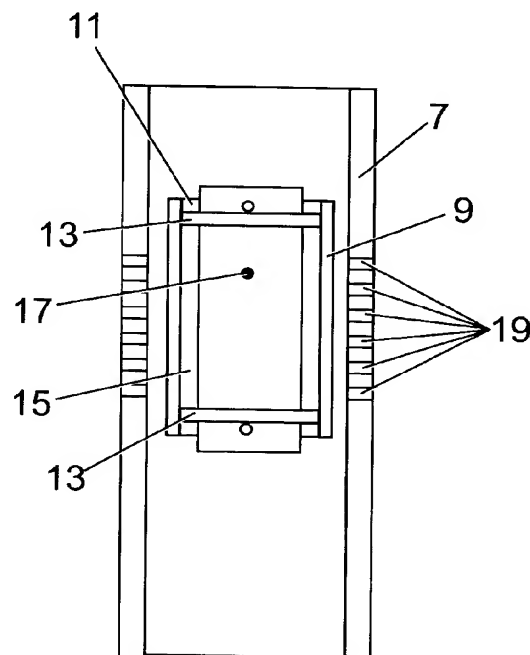
(52) UK CL (Edition W ):  
**E1F FLA**

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**EP 1165933 A1** **EP 0937861 A3**  
**WO 2004/015241 A1** **US 20020020524 A1**

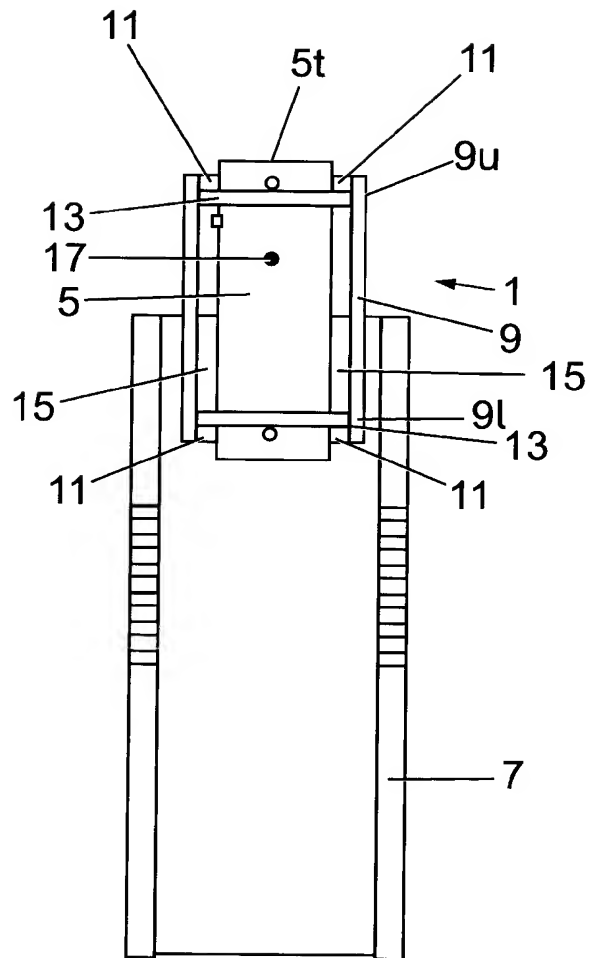
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UK CL (Edition W ) **E1F**  
INT CL<sup>7</sup> **E21B**  
Other: **Online: EPODOC, WPI, PAJ, OPTICS**

(54) Abstract Title: **Downhole tubular sealing apparatus**

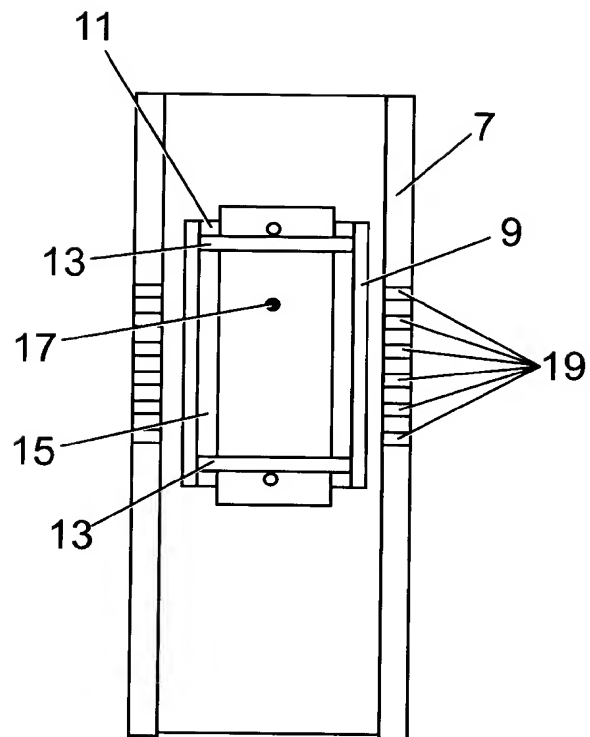
(57) A downhole tubular sealing apparatus and method for sealing a tubular 9 within a second tubular 7 comprises at least one seal 13 associated with an inner tubular 9. A pressure control device 17 is employed to radially expand the tubular member 9 so that it bears against the inner surface of the outer tubular (7, figure 5), which may be a liner or a borehole wall. In a preferred embodiment, the tubular member being expanded undergoes elastic and plastic deformation, and in a particularly preferred embodiment, expansion continues until the outer tubular also suffers deformation. Other embodiments are also disclosed, these being sealing means for an annular space, a method of plugging a downhole tubular, and a method of providing a downhole metal to metal seal.



*Fig. 2*



*Fig. 1*



*Fig. 2*

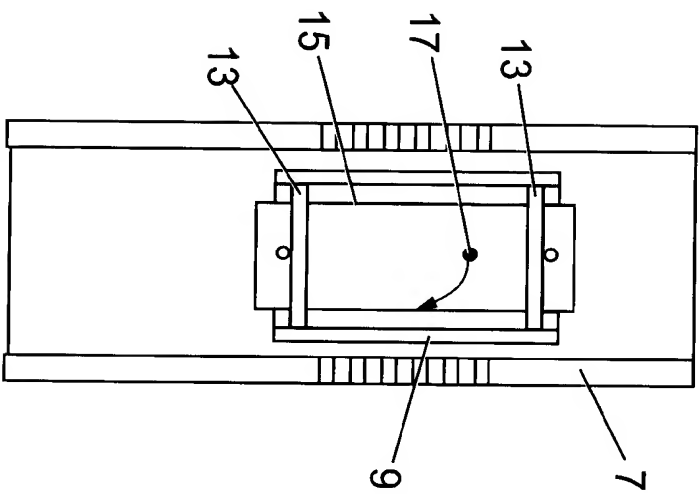


Fig. 3

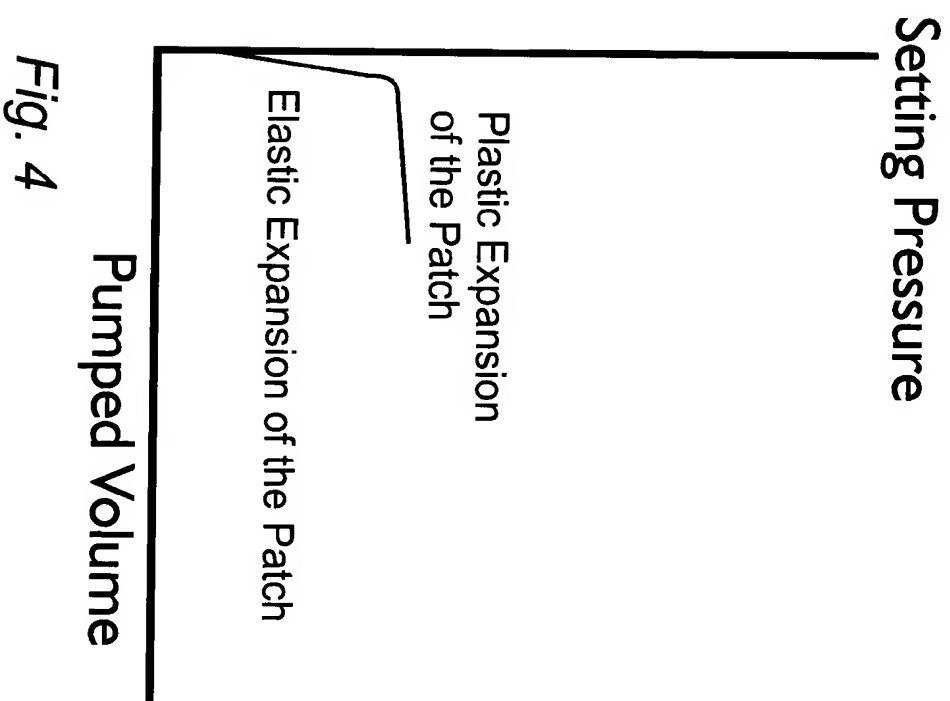


Fig. 4

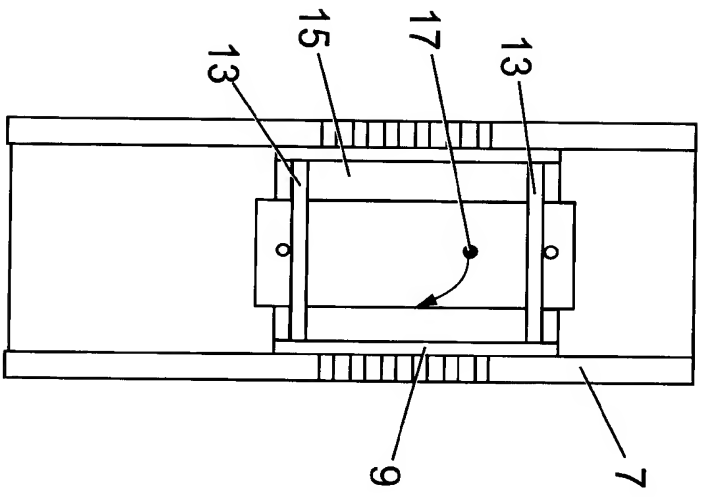


Fig. 5

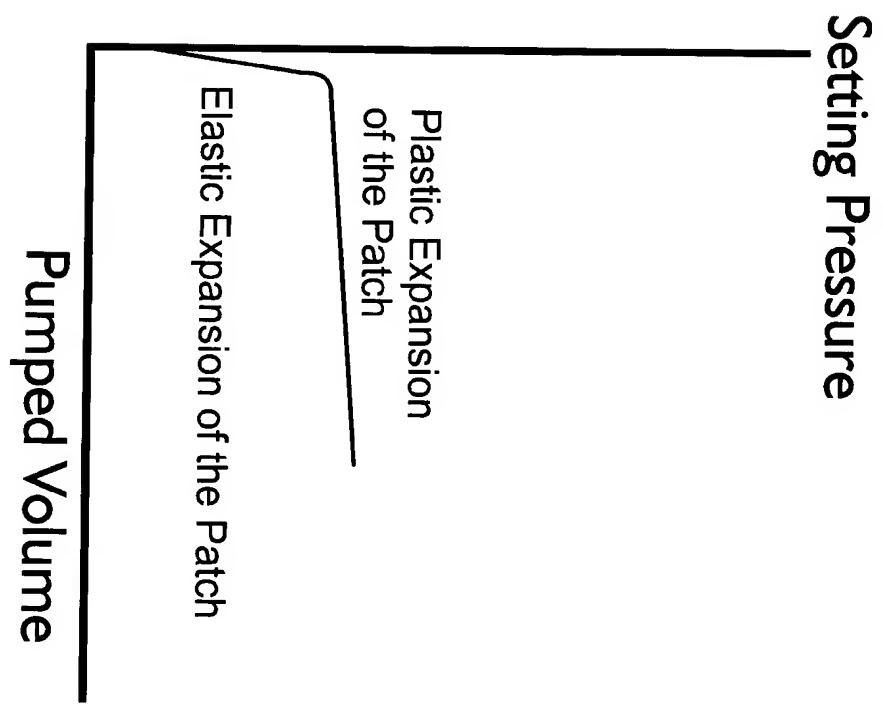


Fig. 6

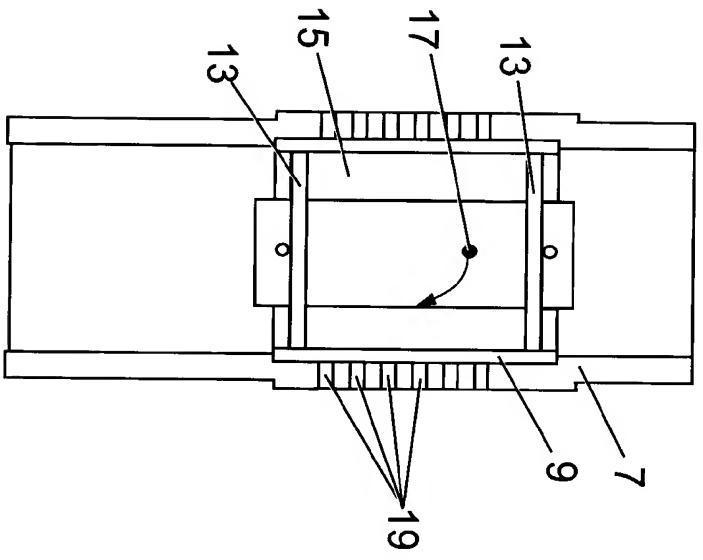


Fig. 7

Setting Pressure

Plastic Expansion  
of the Patch

Plastic Expansion of the Patch  
Elastic Expansion of the Liner

Elastic Expansion of the Patch

Pumped Volume

Fig. 8

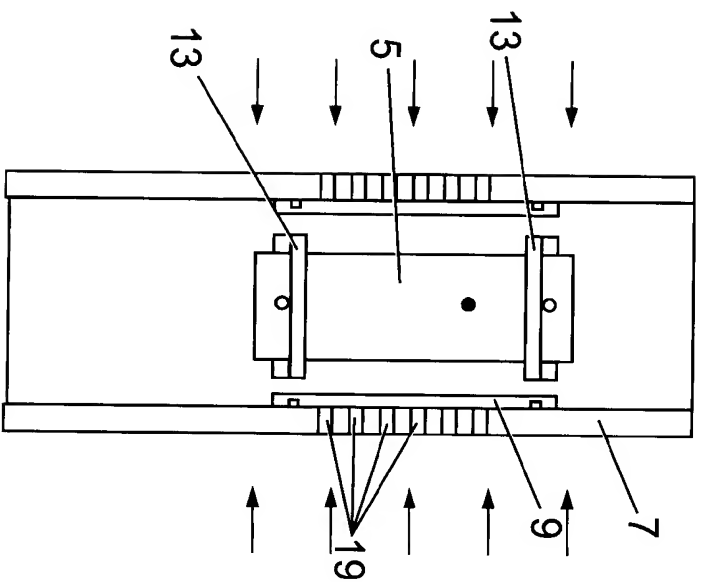


Fig. 9

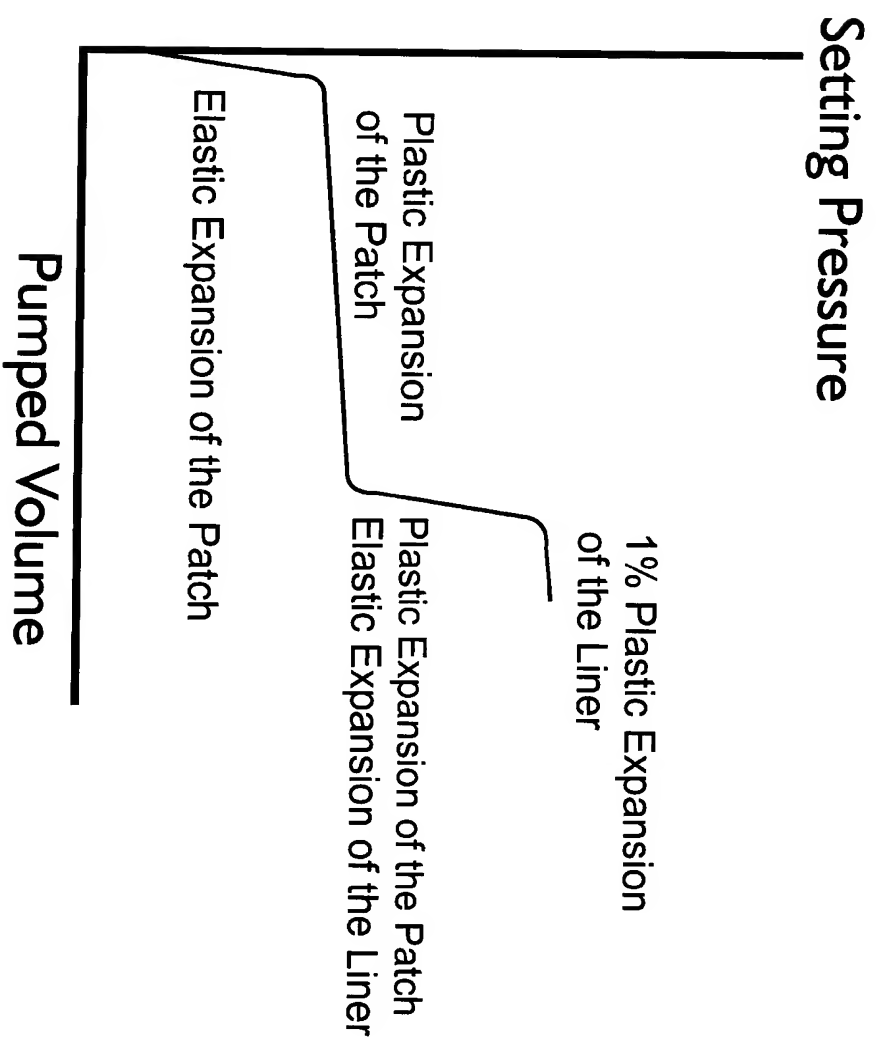
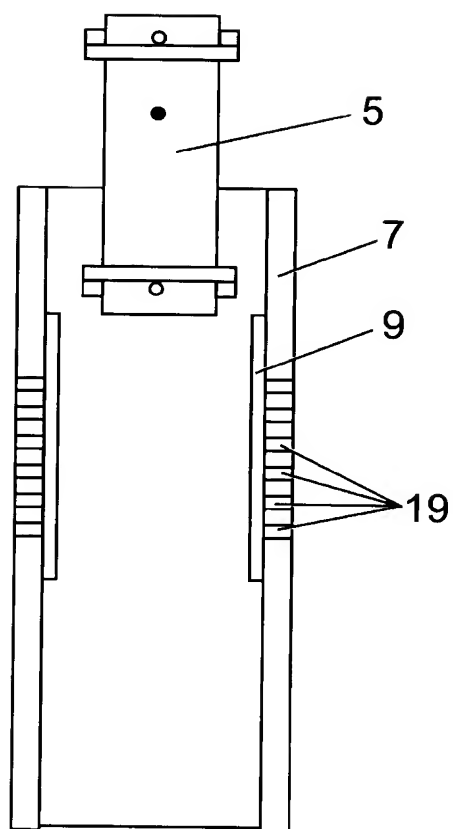
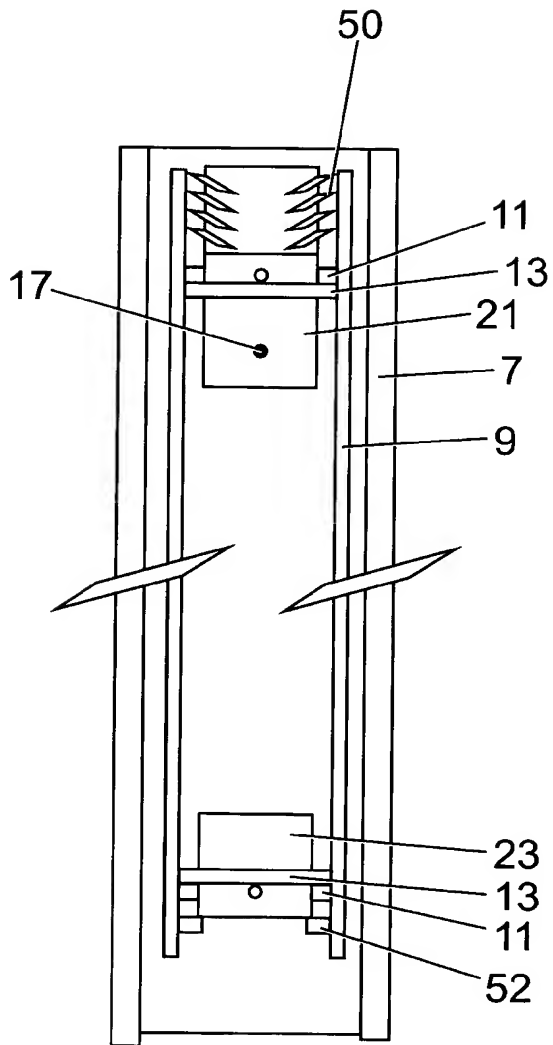


Fig. 10

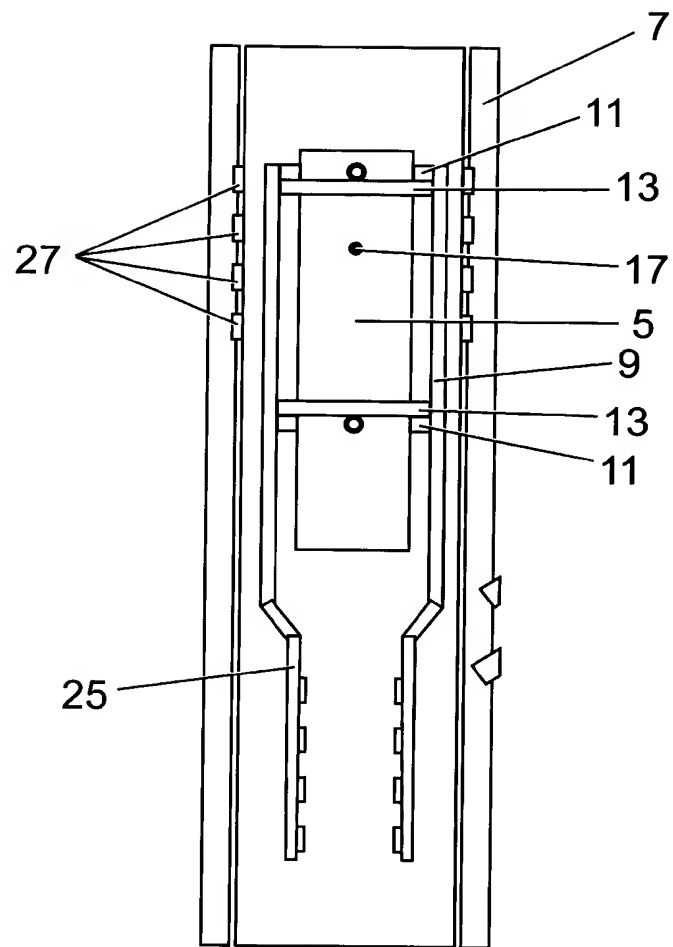


*Fig. 11*

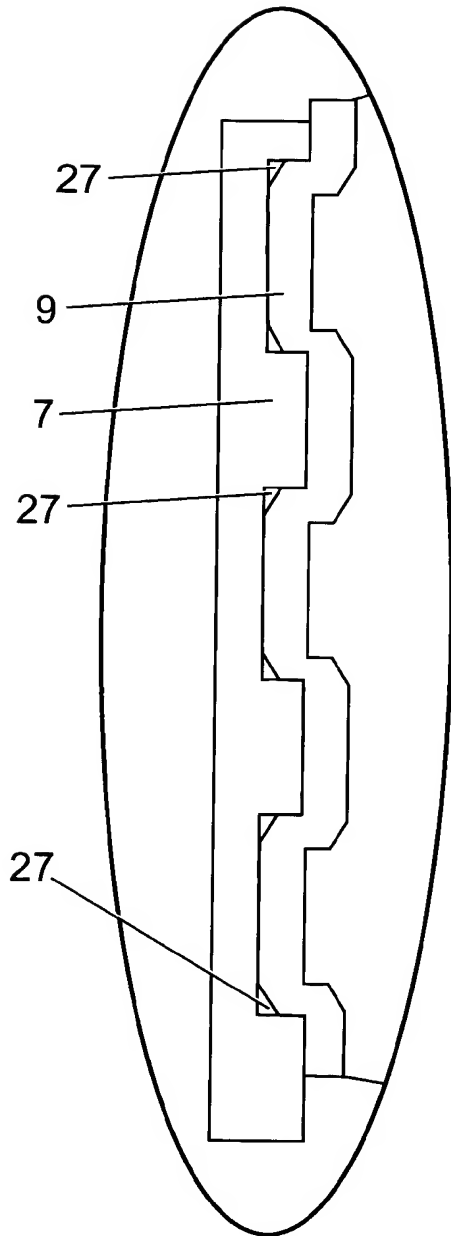




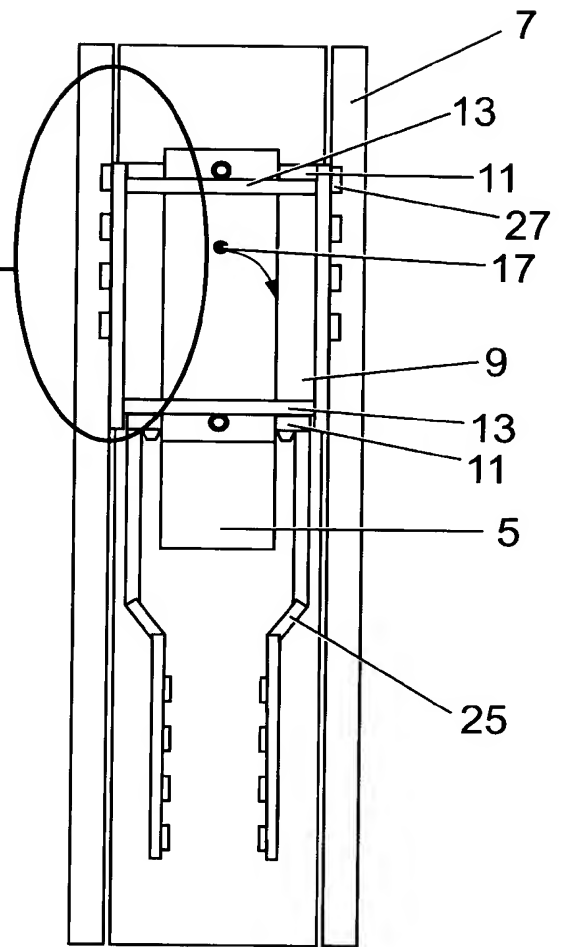
*Fig. 12*



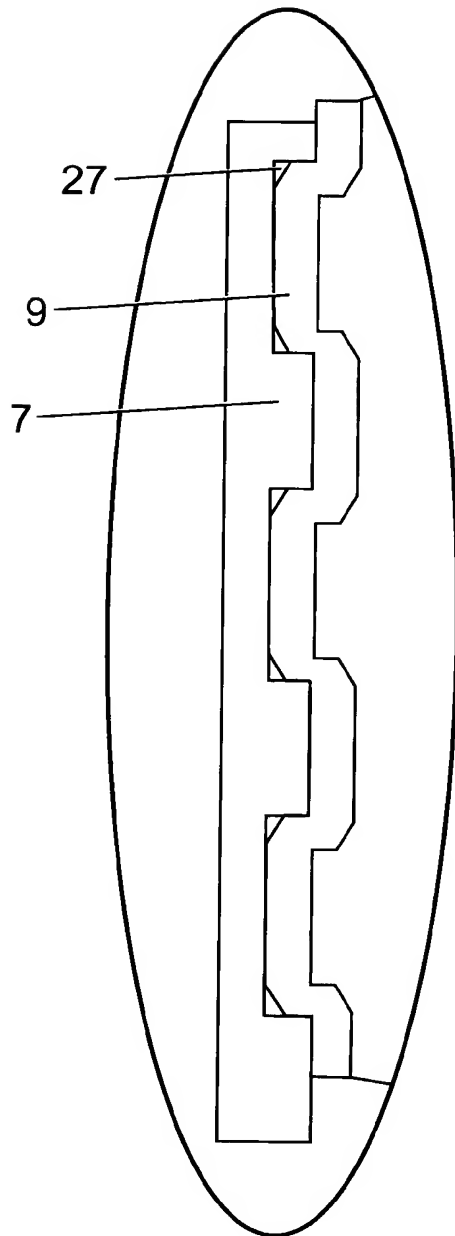
*Fig. 13*



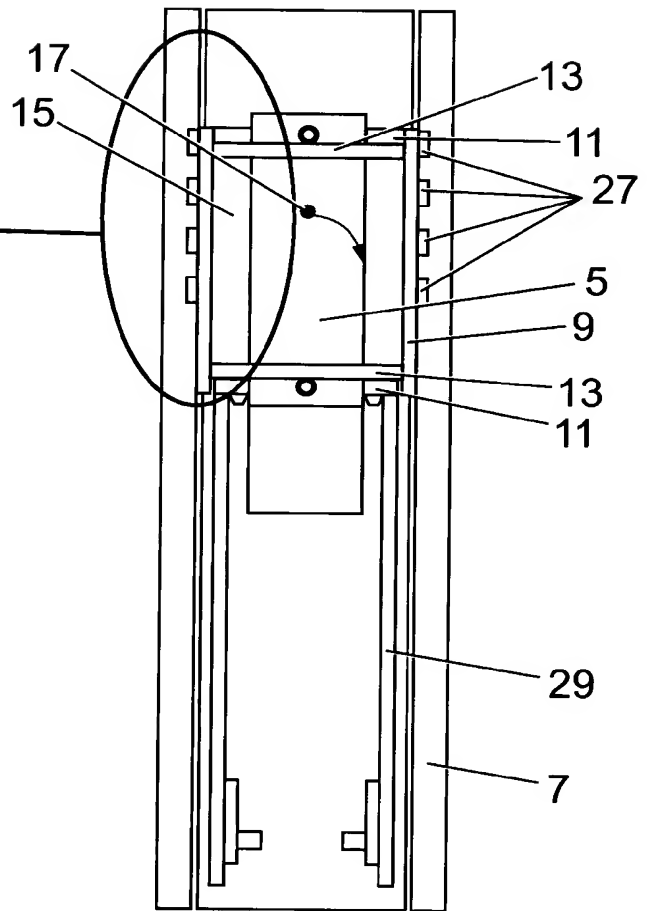
*Fig. 14b*



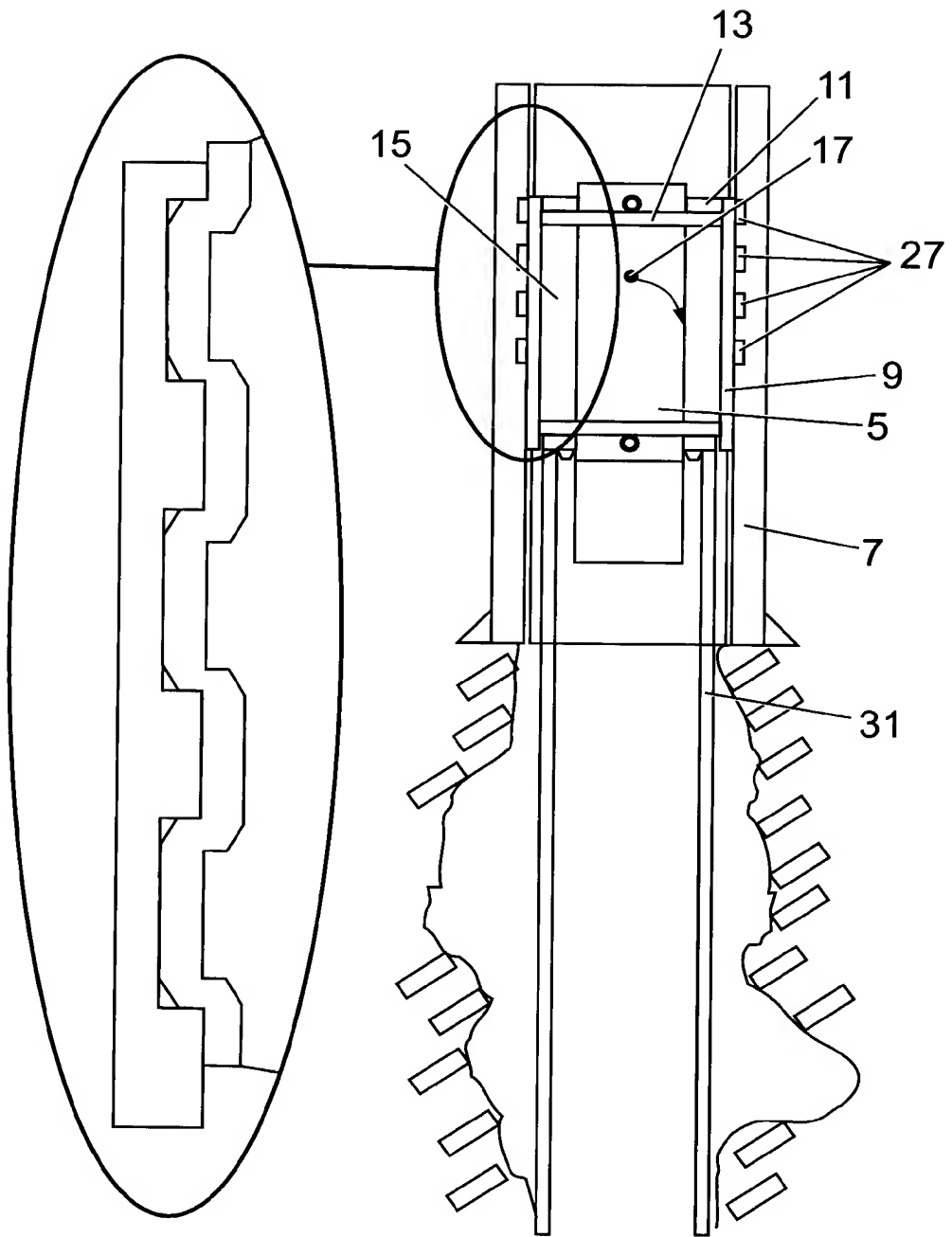
*Fig. 14a*



*Fig. 15b*

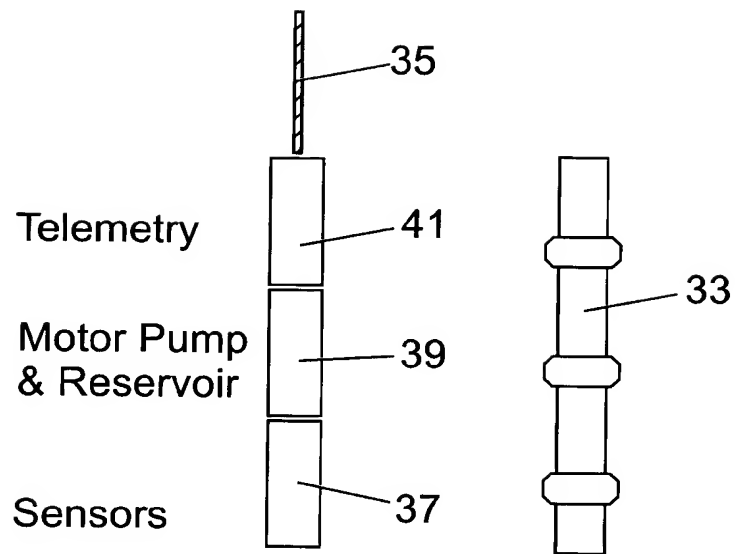


*Fig. 15a*



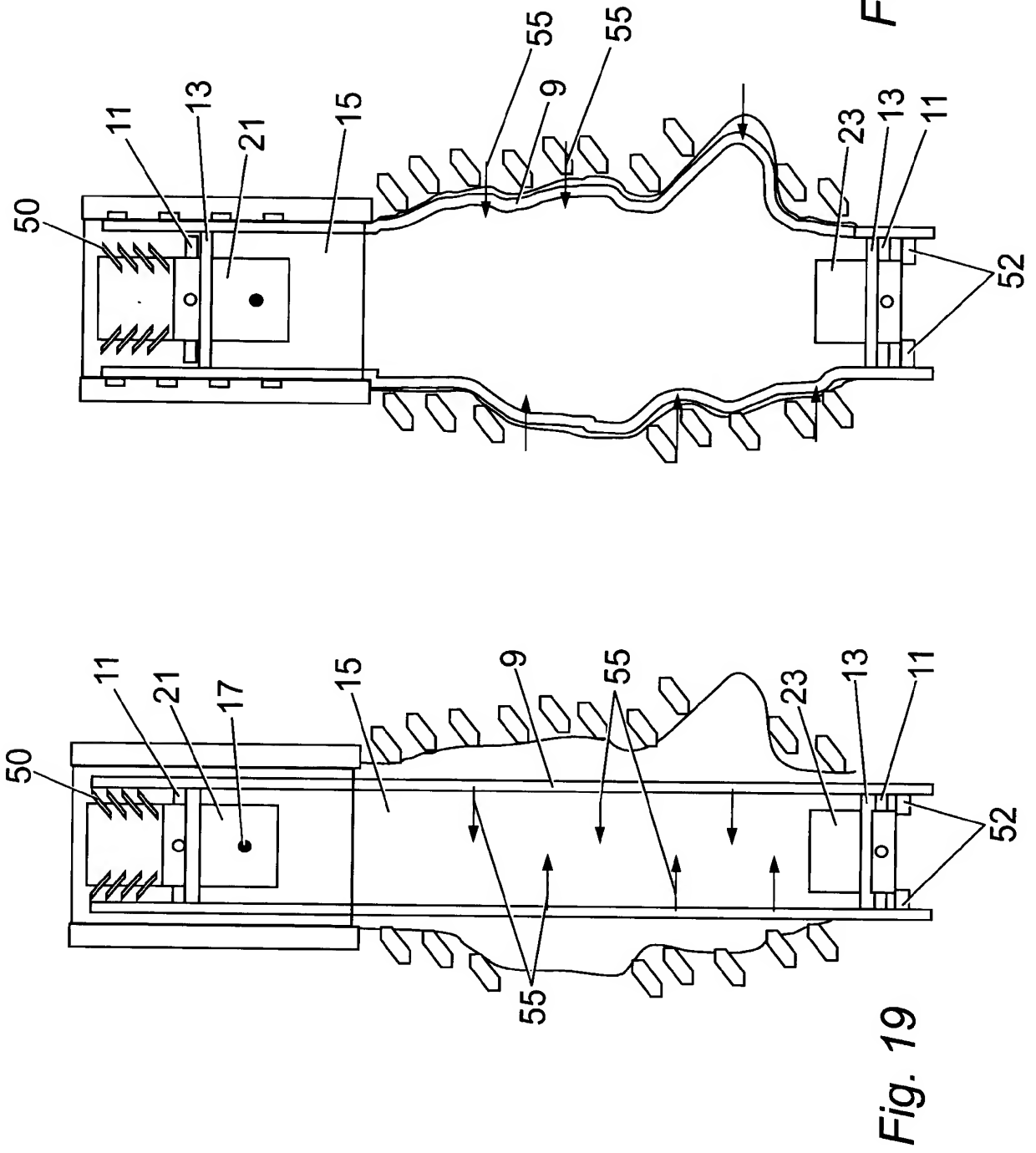
*Fig. 16b*

*Fig. 16a*



*Fig. 17*

*Fig. 18*



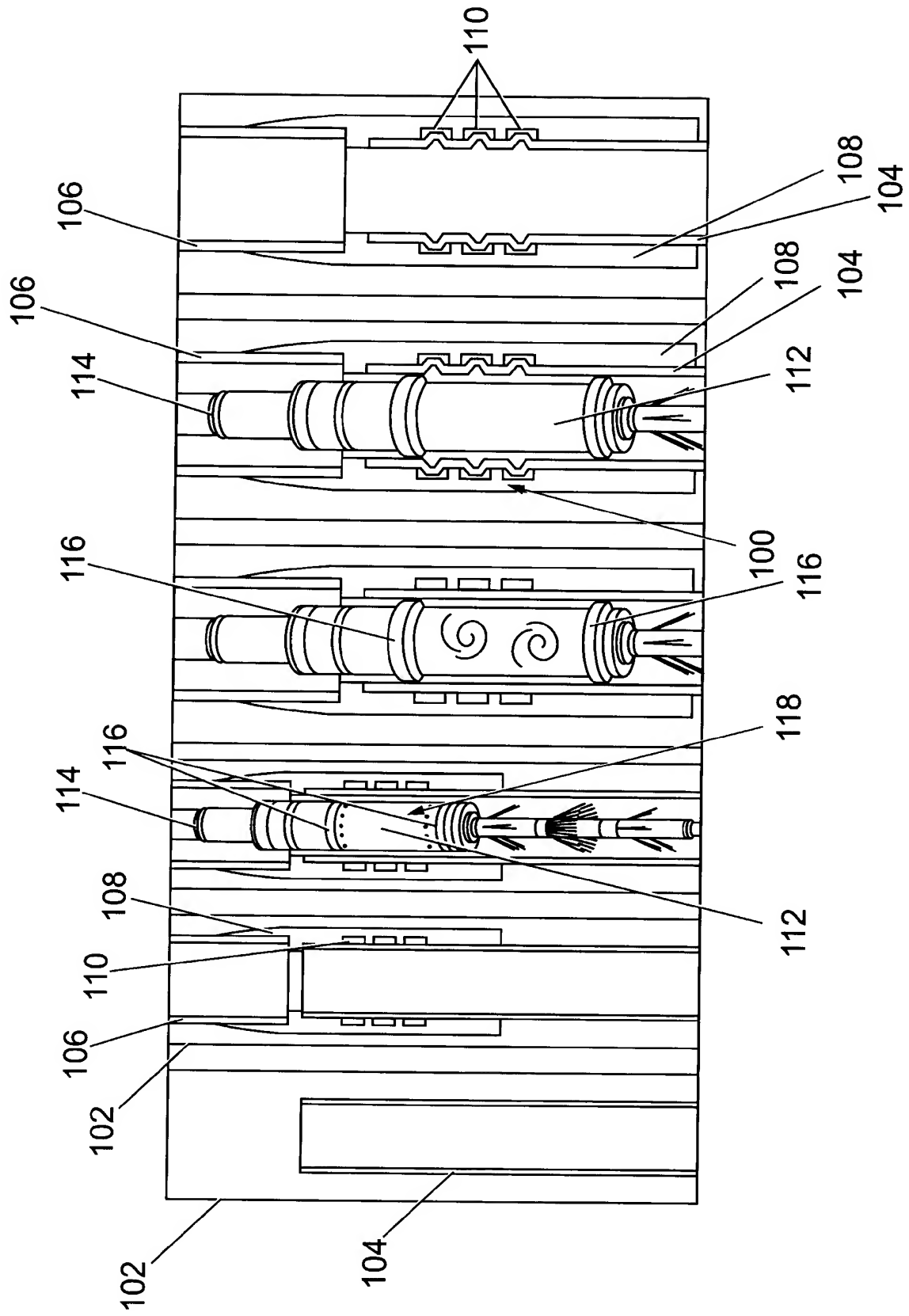
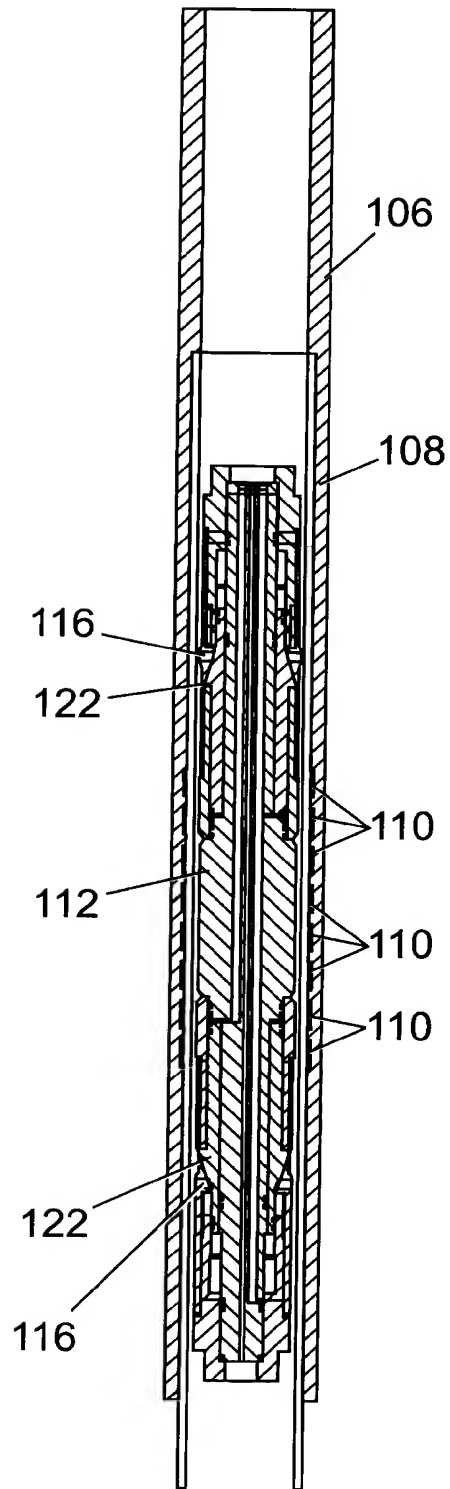


Fig. 21 Fig. 22 Fig. 23 Fig. 24 Fig. 25 Fig. 26





*Fig. 27*

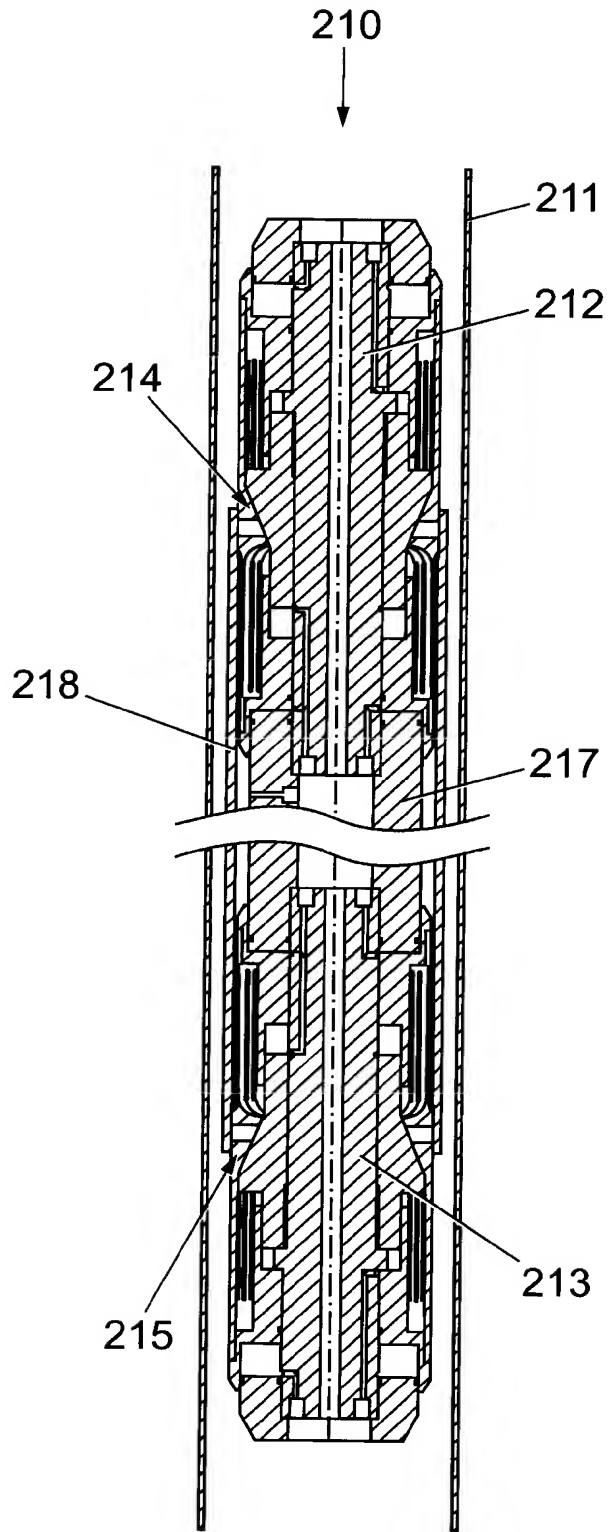


Fig. 28

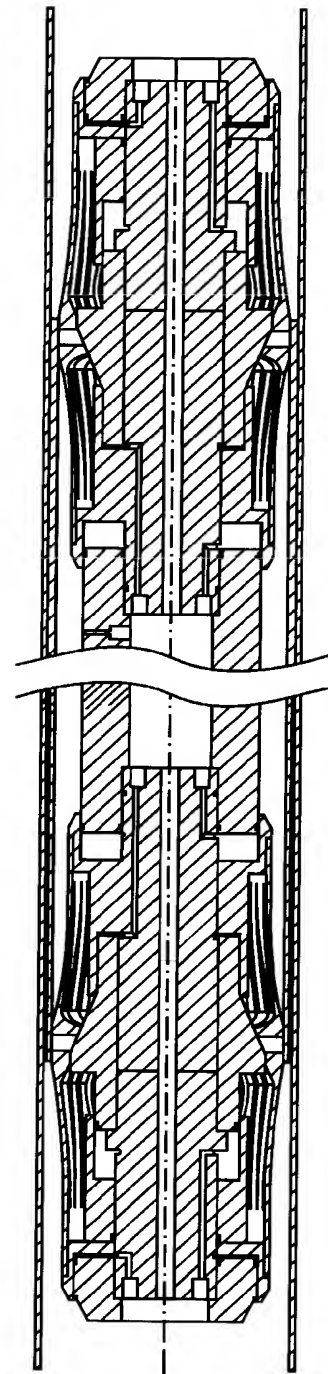
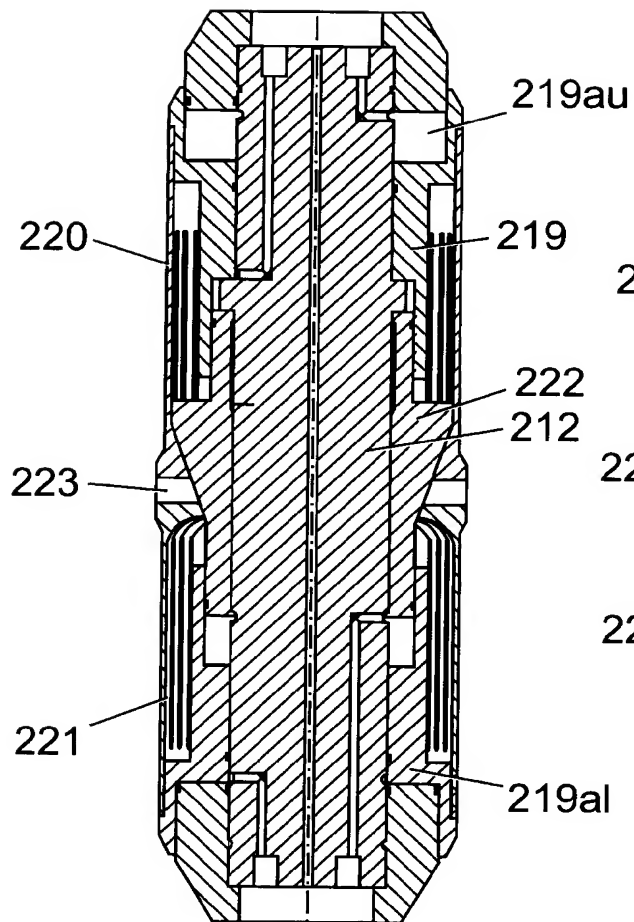
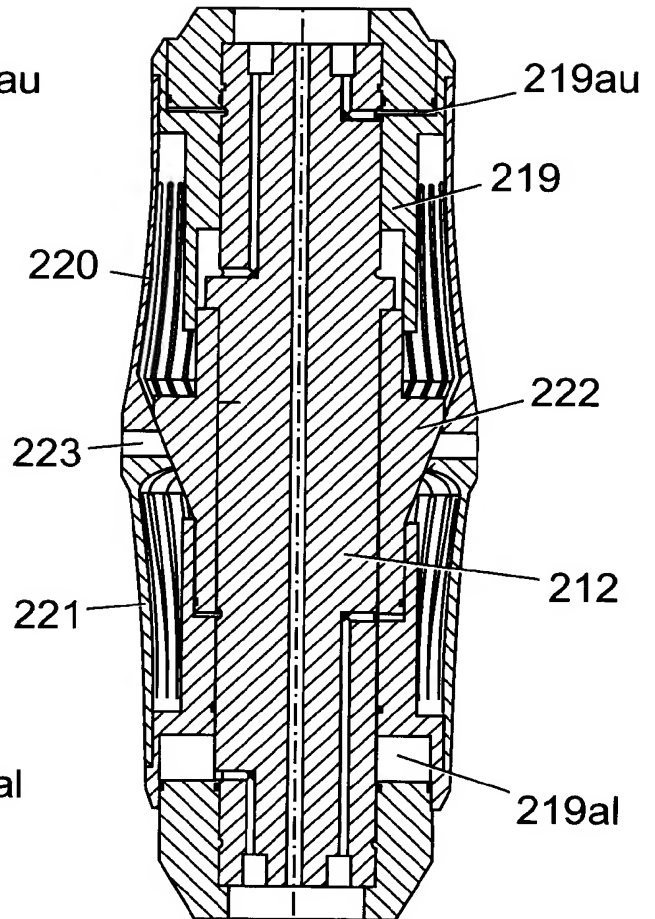


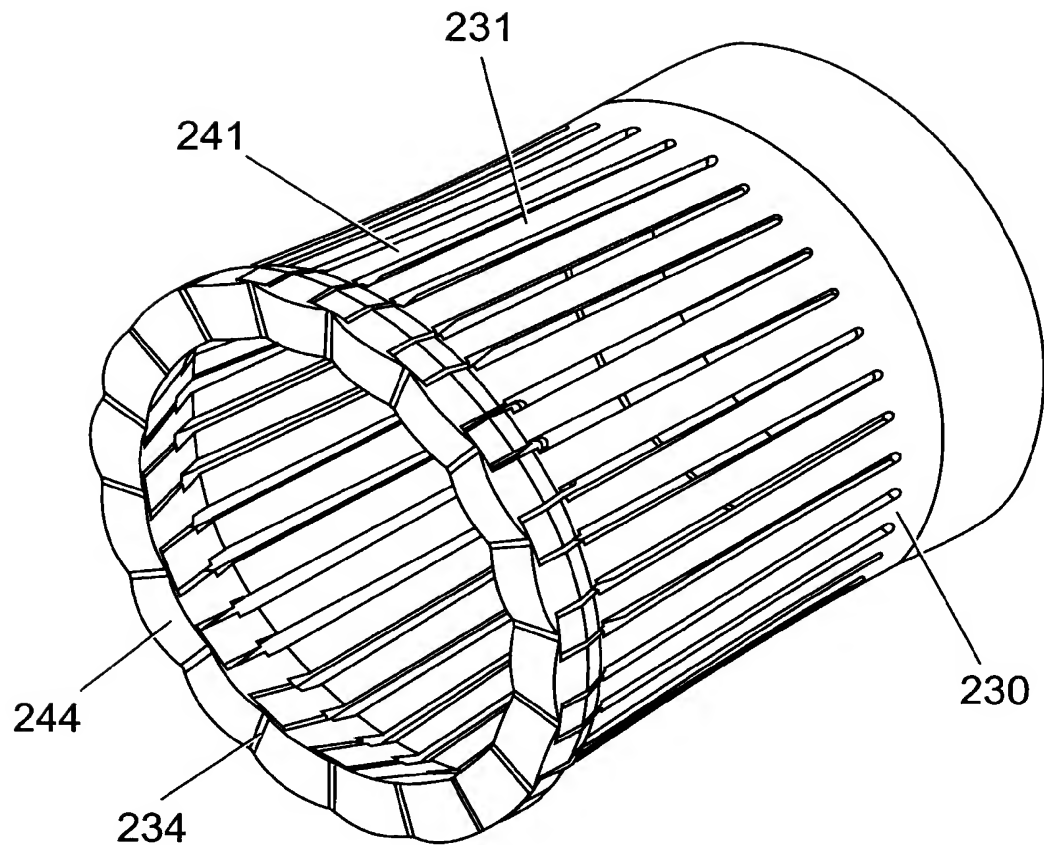
Fig. 29



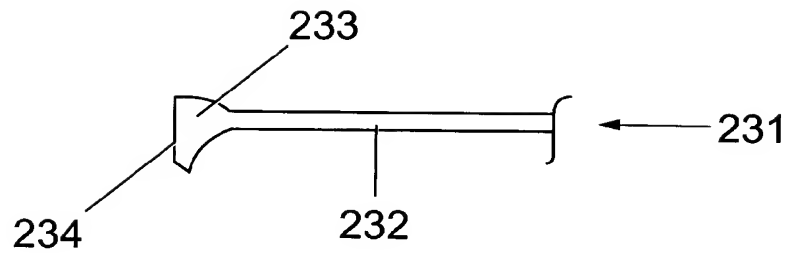
*Fig. 30*



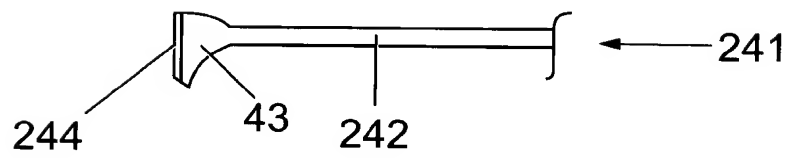
*Fig. 31*



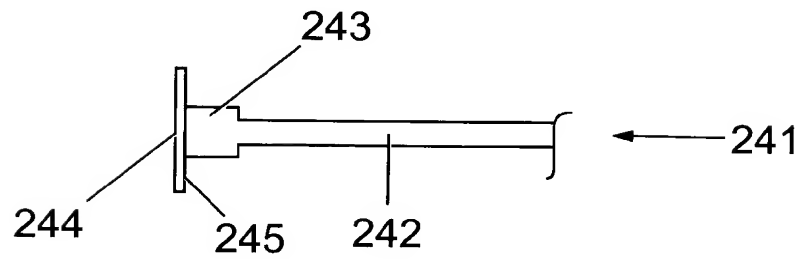
*Fig. 32*



*Fig. 33a*



*Fig. 33b*



*Fig. 33c*

1     "Apparatus and Method"

2

3     The present invention relates to an apparatus and  
4     method, particularly but not exclusively, for  
5     deploying and/or securing a tubular section referred  
6     to as a "tubular member" within a liner or borehole.

7

8     Oil or gas wells are conventionally drilled with a  
9     drill string at which point the open hole is not  
10    lined, hereinafter referred to as a "borehole".

11    After drilling, the oil, water or gas well is  
12    typically completed thereafter with a casing or  
13    liner and a production tubing, all of which from  
14    here on are referred to as a "liner".

15

16    Conventionally, during the drilling, production or  
17    workover phase of an oil, water or gas well, and  
18    from a first aspect of the present invention, there  
19    may be a requirement to provide a patch or temporary  
20    casing across an interval, such as a damaged section  
21    of liner, or an open hole section of the borehole.

22

1     Additionally, and from a second aspect of the  
2     present invention, there may be a requirement to cut  
3     a tubular (such as a section of casing) downhole,  
4     remove the upper free part and replace it with a new  
5     upper length of tubular in an operation know as a  
6     "tie back" and in such a situation it is important  
7     to obtain a solid metal to metal seal between the  
8     lower "old" tubular section and upper "new" tubular  
9     section.

10

11     Additionally, from a third aspect, the present  
12     invention relates to a seal packer for subterranean  
13     wells which can be used to isolate two zones in an  
14     annular space of such wells, or to join two tubes  
15     together, etc.

16

17     The use of radially expandable packers is well known  
18     in the art. These packers, or seals, are frequently  
19     used to do maintenance in areas over the packer, or  
20     to seal off a particular formation, for example a  
21     water producing zone of the well.

22

23     Generally, there are two types of packers, the first  
24     type is inflatable rubber packers and the second  
25     type is compact rubber packers. The two types have  
26     different characteristics when it comes to the  
27     expansion ability and temperature and pressure  
28     tolerance. Today, even more well environments have  
29     high temperature and pressure, and it is a challenge  
30     to develop reliable equipment for such environments.  
31     The prior art have some disadvantages, for example  
32     the high temperature and high pressure can cause

1 extruding of the packer. Consequently, this may  
2 result in a leakage. Another disadvantage is that  
3 some packers after compression in well bores with  
4 extreme temperatures and pressures will not function  
5 properly, for example the relaxation of the packer  
6 can work poorly.

7

8 There have been several attempts to solve the  
9 disadvantages mentioned above.

10

11 GB Patent Publication No 2296520A describes oil/gas  
12 well tools related to a sealing/packing tool which  
13 provides a pressure/fluid barrier. It provides a  
14 downhole tool comprising at least one ring with  
15 petaloid extensions, said ring being disposed about  
16 a longitudinal axis of the said tool, and means for  
17 controllably deforming said petaloid extensions such  
18 that said extensions may be controllably moved in  
19 use. Said controllable movement may cause the  
20 extensions to be brought into close proximity with  
21 an inner surface of a conduit. Said tool may  
22 further comprise an elastically deformable packing  
23 element. The extensions are expanded by a wedge  
24 surface on the ring and help to centre the tool in  
25 the conduit. The extensions may also be arranged to  
26 act as anti extrusion means for the packing element.

27

28 US Patent Publication No 5226492 describes a packer  
29 for sealing an annular space comprising a deformable  
30 hollow metallic sleeve having an inner cavity which  
31 has an open end. The sleeve is preferably cone  
32 shaped. An expandable member is disposed within the



1 inner cavity. A wedge member is located in close  
2 proximity to the expandable member, and serves to  
3 transmit a compressive force to the expandable  
4 member to obtain the desired radial expansion of the  
5 sleeve. The compression causes the expandable  
6 member to be forced around the outside of the wedge  
7 member and forms a first seal between the expandable  
8 member and an annular production casing. The rim of  
9 the metallic sleeve is also in contact with the  
10 production casing and accordingly a second seal is  
11 formed. Further, the metallic sleeve may comprise  
12 one or more slots at desired intervals to facilitate  
13 the deformation of the metallic sleeve.  
14 Additionally, a seal obtained using an additional  
15 band provides improved sealing due to an additional  
16 seal formed between the additional band and the  
17 inner wall of the production casing.

18  
19 The main object of the third aspect of the invention  
20 is to provide a device which avoids the  
21 disadvantages of the prior art. The device  
22 according to the invention should be able to seal an  
23 annular tube, and also to join two tubes together,  
24 in a so-called swage process. Consequently, this  
25 requires considerable forces to be applied, which  
26 again demand packers with special properties.

27  
28 According to a first aspect of the present  
29 invention, there is provided a method of securing a  
30 tubular member within a liner or borehole of a well,  
31 the method comprising:-

1           inserting the tubular member into the borehole;  
2    and

3           increasing the pressure within the tubular  
4    member between a pair of seal means associated with  
5    the tubular member, such that the pressure increase  
6    causes the tubular member to move radially outwardly  
7    to bear against the inner surface of the liner or  
8    borehole.

9  
10   According to the first aspect of the present  
11   invention, there is also provided an apparatus for  
12   securing a tubular member within a liner or  
13   borehole, the apparatus comprising at least one seal  
14   means associated with the tubular member, and a  
15   pressure control means operable to increase the  
16   pressure within the tubular member, such that  
17   operation of the pressure control means causes the  
18   tubular member to move radially outwardly to bear  
19   against the inner surface of the liner or borehole  
20   wall.

21  
22   Preferably, the pressure control means is also  
23   operable to monitor the pressure within the tubular  
24   member. Typically, the pressure control means is  
25   also operable to control the pressure within the  
26   tubular member.

27  
28   Typically, the apparatus comprises a pair of seal  
29   means, and more preferably comprises a pair of  
30   sealing devices in accordance with the third aspect  
31   of the present invention. Typically, the pressure  
32   is preferably increased within the tubular member

1     between the pair of seal means. The pressure may be  
2     provided by a hydraulic fluid.

3

4     The tubular member may be coupled to an apparatus  
5     for use within the borehole, such as a nipple  
6     profile, seal assy, seal bore receptacle, temporary  
7     liner/tubing section or other apparatus.

8

9     Typically, the method of the first aspect further  
10    comprises inserting the tubular member into the  
11    liner or borehole to the required depth. Conveyance  
12    of the apparatus may be by way of wireline, coil  
13    tubing or drill pipe.

14

15    The tubular member is typically in the form of a  
16    patch, and is preferably moved radially outwardly  
17    such that the tubular member undergoes elastic  
18    deformation and also plastic deformation. The  
19    tubular member or patch member is preferably formed  
20    from a suitable metal material, such as steel or an  
21    alloy material, and may be provided with a coating  
22    such as an elastomeric coating and/or a non-uniform  
23    outer surface such as a ribbed, grooved or other  
24    form of surface, in order to increase the  
25    effectiveness of the seal created by the tubular  
26    member when it is secured to the liner or borehole.

27

28    Typically, the apparatus further comprises a body  
29    located within the tubular member, and preferably  
30    located co-axially within the tubular member.  
31    Preferably, the pair of seal means are mounted upon  
32    the body and may be energised to seal against the

1 inner surface of the tubular member. Typically, the  
2 body comprises a port to permit the flow of fluid  
3 into, and preferably to allow the flow of fluid out  
4 of, a chamber which is preferably defined by the  
5 outer surface of the body, inner surface of the  
6 tubular member, and inner faces of the pair of seal  
7 means. Preferably, the seal means are in the form  
8 of packer elements or segments, and which may be  
9 provided with back-up rings, which may be formed  
10 from steel. The body may contain  
11 hydraulic/electrical systems to control the flow of  
12 fluid, pressure and/or activate/de-activate the  
13 seals.

14  
15 Typically, the pressure, flow volume, depth and  
16 diameter of the tubular at any given time will be  
17 monitored and recorded by either downhole  
18 instrumentation or surface instrumentation.

19  
20 Preferably, the tubular member is releasably coupled  
21 to the body by means of a coupling means, which may  
22 comprise retractable pins or slips. The retractable  
23 pins or slips are preferably initially locked to the  
24 tubular member, and typically, after operation of  
25 the apparatus such that the tubular member has  
26 reached the desired level of expansion, the pins or  
27 slips are retracted inwardly toward the body, such  
28 that the engagement between the pins or slips and  
29 the tubular member is broken.

30  
31 The tubular member is typically moved radially  
32 outwardly by the pressure to bear against the inner

1 surface of the liner or borehole wall. Optionally,  
2 the tubular member or liner may be provided with a  
3 surface that facilitates providing engagement  
4 between the liner and the tubular member, and the  
5 said surface may comprise one or more recesses,  
6 coatings or non-uniform surfaces such as grooves,  
7 ribs or the like. This has the advantage of  
8 increasing the resistance to lateral movement  
9 occurring between the liner and the tubular member  
10 preventing the tubular member from being pushed down  
11 or pulled out of the liner or borehole.

12  
13 Additional seal means may be utilised to provide a  
14 seal between the tubular member and the inside wall  
15 of the liner. The additional seal means may be  
16 provided by the (typically metal to metal)  
17 engagement between the inner surface of the liner  
18 and the outer surface of the tubular member to  
19 provide a hydraulic and/or gas seal therebetween.  
20 Alternatively, or in addition, further additional  
21 seal means may be provided, typically on the outer  
22 surface of the tubular member, to provide a  
23 hydraulic and/or gas seal between the tubular member  
24 and the liner. The further additional seal means  
25 may be formed from an elastomeric material and may  
26 be provided in the form of a band or a ring.

27  
28 According to a second aspect of the present  
29 invention, there is provided a method of securing a  
30 first tubular member to a second tubular member  
31 already located within a liner or borehole of a  
32 well, the method comprising:-

1           inserting the first tubular member into the  
2   borehole such that a lower end thereof is in close  
3   proximity with an upper end of the second tubular  
4   member; and

5           increasing the pressure within one of the first  
6   and second tubular members between a pair of seal  
7   means associated with one of the first and second  
8   tubular members, such that the pressure increase  
9   causes one of the first and second tubular members  
10   to move radially to bear against a surface of the  
11   other of the first and second tubular members,  
12   wherein at least one of the first and second tubular  
13   members undergo elastic deformation and also plastic  
14   deformation.

15

16   According to the second aspect of the present  
17   invention, there is also provided an apparatus for  
18   securing a first tubular member to a second tubular  
19   member already located within a liner of borehole of  
20   a well, the apparatus comprising:-

21           a pair of seal means associated with one of the  
22   first and second tubular members;

23           and a pressure control means operable to  
24   increase the pressure within one of the first and  
25   second tubular members between the pair of seal  
26   means;

27           such that operation of the pressure control  
28   means causes one of the first and second tubular  
29   members to move radially to bear against a surface  
30   of the other of the first and second tubular  
31   members;

1           such that at least one of the first and second  
2   tubular members undergo elastic deformation and also  
3   plastic deformation.

4  
5   Preferably, the pressure control means is also  
6   operable to monitor the pressure within the tubular  
7   member. Typically, the pressure control means is  
8   also operable to control the pressure within said  
9   one of the first and second tubular members.

10

11   Typically, the pair of seal means are associated  
12   second tubular member, and preferably the pair of  
13   seal means are mounted on a body member.

14   Preferably, the body member is lowered into the  
15   wellbore, typically through the first tubular  
16   member, by an elongate member such as a string of  
17   drill pipe, coiled tubing or wireline and is further  
18   lowered into the second tubular member. Preferably,  
19   the body member is lowered to the proximate to the  
20   upper end of the second tubular member until the  
21   body member is generally aligned with one or more  
22   profiles formed on a surface of the first tubular  
23   member. Typically, the profiles are formed on an  
24   internal surface of the first tubular member.

25   Preferably, an overshot device is provided at or  
26   toward the lower end of the first tubular member and  
27   the one or more profiles are formed on an inner bore  
28   of the overshot device. Preferably, the pair of  
29   seal means are longitudinally spaced apart on the  
30   body member and the pair of seal means are typically  
31   arranged such that they are spaced further apart  
32   than the longitudinal extent of the one or more

1 profiles. Typically, the body member is lowered  
2 into the first body member until the pair of seal  
3 means straddle the one or more profiles.

4  
5 Preferably, the pair of seal means are actuated to  
6 seal against the inner bore of the second tubular  
7 member. Preferably, the body member is provided  
8 with one or more fluid ports or apertures typically  
9 in its sidewall. Preferably, a fluid, which may be  
10 a hydraulic fluid, is used to provide the pressure  
11 and typically the fluid is pumped through the first  
12 tubular member or if possible the elongate member,  
13 through the one or more fluid ports and into a  
14 chamber defined between the outer surface of the  
15 body member, the inner bore of the first tubular  
16 member and the pair of seal means. Typically, once  
17 the pressure has increased to a sufficient level,  
18 one or more portions, which are preferably  
19 circumferential portions, of the first tubular  
20 member are expanded or swaged into a respective  
21 number of the one or more profiles of the overshoot  
22 device to form a joint between the first tubular  
23 member and the overshoot device of the second tubular  
24 member. Accordingly, the one or more portions of  
25 the second tubular member are preferably moved  
26 radially outwardly such that the one or more  
27 portions undergo elastic deformation and also  
28 plastic deformation. The first tubular member is  
29 preferably formed from a suitable metal material,  
30 such as steel or an alloy material.

31



1 Preferably, the pair of seal means comprise a pair  
2 of sealing devices in accordance with the third  
3 aspect of the present invention.

4  
5 Typically, the method according to the second aspect  
6 of the present invention further comprises pulling  
7 the elongate member and the body member out of the  
8 well.

9  
10 Preferably, the seal means are in the form of packer  
11 elements or segments, and which may be provided with  
12 support means.

13  
14 Typically, the pressure, flow volume, depth and  
15 diameter of the tubular at any given time will be  
16 monitored and recorded by either downhole  
17 instrumentation or surface instrumentation.

18  
19 According to a third aspect of the present invention  
20 there is provided a sealing device for use in an  
21 annular space, where the sealing device comprises:-  
22 at least one substantially cylindrical inner  
23 element;

24 at least one seal assembly; and  
25 a displacement means operable to apply a force  
26 on the said seal assembly;

27 where the said inner element comprises a wedge  
28 member, and the said seal assembly is slidable over  
29 the wedge member along the longitudinal direction of  
30 the inner element, wherein the said seal assembly  
31 expands radially outward when forced over the wedge  
32 member;

1           the seal assembly comprising a radially  
2       expandable annular seal supported by at least one  
3       radially expandable support sleeve;

4           characterised in that the support sleeve forms  
5       a substantially continuous support surface towards  
6       the said annular seal in both expanded and non-  
7       expanded positions.

8  
9       Preferably, the support sleeve comprises fingers  
10      supporting the said annular seal and more preferably  
11      the support sleeve comprises at least two types of  
12      fingers. Typically, the sealing device comprises  
13      two radially expandable support sleeves.

14  
15      Preferably, the sealing device is a packer device  
16      for use in a production tube, casing tube, liner  
17      tube or the like. Typically, the displacement means  
18      is disposed between the said inner element and the  
19      said seal assembly. Preferably, the fingers are  
20      connected to an end of their respective support  
21      sleeve.

22  
23      Typically, the first type of finger comprises a  
24      generally triangular support member, the end surface  
25      of which defines a support surface and the second  
26      type of finger preferably comprises a generally  
27      triangular support member being generally T-shaped  
28      seen from above, the end of which defines a support  
29      surface, where the other side of the support member  
30      defines a support surface. More preferably, every  
31      second finger of the support sleeve is of the first

1 type of finger, or the second type of finger  
2 respectively.

3

4 Preferably, the support surfaces of the second type  
5 of fingers in a running in hole position rest on the  
6 support surfaces of the first type of fingers.

7 Typically, the support surfaces of the second type  
8 of fingers in a running in hole position are resting  
9 on at least some of the support surfaces of the  
10 first type of fingers.

11

12 Typically there are at least two packer devices  
13 connected by means of a mandrel. Preferably, an  
14 annular sleeve is disposed between the at least two  
15 packer devices and the production tube, said annular  
16 sleeve being disposed in a longitudinal direction  
17 between two seal assemblies, wherein the annular  
18 sleeve preferably provides a sealing surface towards  
19 the production tube.

20

21 Alternatively, an isolation plug is provided which  
22 comprises one packer device which could be run on  
23 drill pipe, coil tubing or wireline. Setting of the  
24 plug may be by hydraulic or mechanical means.

25 Typically, a seal setting piston is attached to a  
26 mandrel which protrudes through an upper end of the  
27 single packer device of the plug. Preferably, the  
28 mandrel is attached to a setting tool, such that  
29 when the mandrel is pulled upwards against a sleeve  
30 mounted against the upper end of the single packer  
31 device or isolation plug, the annular seal is  
32 activated and is extruded outwardly to contact the

1 casing wall or downhole tubular, for instance.  
2 Final setting loads of the plug may be set via  
3 either a mechanical shear means when set  
4 mechanically or via the final hydraulic pressure  
5 when set with hydraulic means. The seal setting  
6 piston would be maintained in the set position via  
7 locking the hydraulics in place for a hydraulic set  
8 or with slips or a ratchet mechanism for mechanical  
9 sets.

10

11 For retrieval of the plug, the annular seal would be  
12 de-activated via releasing the hydraulic pressure or  
13 by releasing the ratchet/slip mechanism.

14

15 For high differential pressures, the setting force  
16 would be sufficiently high to swage the casing or  
17 downhole tubular with the single seal assembly or  
18 isolation plug, thereby key seating the seal  
19 assembly into the well delivering a large resistance  
20 to movement up or down the well.

21

22 According to a fourth aspect of the present  
23 invention there is provided an isolation plug for  
24 plugging a downhole tubular, the isolation plug  
25 comprising a sealing device according to the third  
26 aspect of the present invention and a seal actuation  
27 mechanism, the seal actuation mechanism being  
28 operable to expand the annular seal radially  
29 outwards toward the downhole tubular to firstly seal  
30 against an inner bore thereof and secondly  
31 elastically and furthermore plastically deform the  
32 downhole tubular.

1  
2 According to a fifth aspect of the present invention  
3 there is provided a method of plugging a downhole  
4 tubular comprising inserting an isolation plug into  
5 the downhole tubular to a desired location and  
6 expanding a seal means of the isolation plug in a  
7 radially outwards direction toward the downhole  
8 tubular by operating a seal actuation mechanism of  
9 the isolation plug such that the seal means firstly  
10 seals against an inner bore of the downhole tubular  
11 and secondly elastically and furthermore plastically  
12 deforms the downhole tubular.

13  
14 The seal actuation mechanism may comprise a  
15 hydraulic or mechanical means but preferably  
16 comprises a hydraulic means. The isolation plug may  
17 be run into the downhole tubular on drill pipe, coil  
18 tubing or wireline.

19  
20 According to a sixth aspect of the present invention  
21 there is provided a method of providing a downhole  
22 metal to metal seal between two concentrically  
23 arranged tubulars, comprising the steps of:-

24  
25 a) expanding radially outwardly the innermost  
26 tubular through elastic and then plastic deformation  
27 until it contacts the inner bore of the second  
28 tubular; and

29  
30 b) continued expansion of the first tubular such  
31 that it firstly elastically and secondly plastically  
32 expands the second tubular radially outwardly.

1  
2     Embodiments of the six aspects of the present  
3     invention will now be described, by way of example  
4     only, with reference to the accompanying drawings,  
5     in which:-  
6

7         Fig. 1 is a schematic representation of an  
8         apparatus, in accordance with a first aspect of  
9         the present invention, being conveyed through a  
10        liner on wireline, drill pipe or coiled tubing  
11        toward a location at which it will be operated;  
12        Fig. 2 is a schematic representation of the  
13        apparatus of Fig. 1 adjacent to the location in  
14        the liner at which it will be operated;  
15        Fig. 3 is a schematic representation of the  
16        apparatus of Fig. 1 during its operation;  
17        Fig. 4 is a graph of pumped volume on the X-  
18        axis versus setting pressure on the Y-axis  
19        indicating the expansion of a tubular member  
20        shown in Fig. 3;  
21        Fig. 5 is a schematic representation of the  
22        apparatus of Fig. 1 during continued operation;  
23        Fig. 6 is a table of pumped volume versus  
24        setting pressure indicating the expansion of  
25        the tubular member shown in Fig. 5, the tubular  
26        member now having passed the elastic limit and  
27        going through permanent plastic deformation;  
28        Fig. 7 is a schematic representation of the  
29        apparatus of Fig. 1 after continued operation,  
30        with the tubular member making contact with the  
31        liner wall;

1        Fig. 8 is a table of pumped volume versus  
2        setting pressure for the representation shown  
3        in Fig. 7;  
4        Fig. 9 is a schematic representation of the  
5        apparatus of Fig. 1 after continued operation;  
6        Fig. 10 is a graph of the pumped volume versus  
7        setting pressure for the representation shown  
8        in Fig. 9;  
9        Fig. 11 is a schematic representation of the  
10       apparatus of Fig. 1 following continued  
11       operation;  
12       Fig. 12 is a second embodiment of an apparatus  
13       in accordance with the first aspect of the  
14       present invention, showing a variable length  
15       extrudable liner/casing patch;  
16       Fig. 13 is a third embodiment of an apparatus  
17       in accordance with the first aspect of the  
18       present invention, incorporating a tubing  
19       receptacle and seal assembly (also known as a  
20       seal assy) and due to the heavy loading applied  
21       to the seal assy, the liner is shown with a  
22       recess profile into which the tubular member  
23       will be plastically deformed;  
24       Fig. 14a is a schematic representation of the  
25       seal assy of Fig. 13, after the apparatus has  
26       been operated, showing the plastic deformation  
27       of the tubular member into the recess in the  
28       liner wall;  
29       Fig. 14b is a detailed schematic representation  
30       of a portion of the representation of Fig. 14a  
31       showing the plastic deformation of the tubular  
32       member into the recess in the liner wall;

1        Fig. 15a is a schematic representation of a  
2        fourth embodiment of an apparatus in accordance  
3        with the first aspect of the present invention,  
4        incorporating a nipple profile to be set in a  
5        liner;

6        Fig. 15b is a detailed schematic representation  
7        of a portion of the apparatus of Fig. 15a again  
8        showing the plastic deformation of the tubular  
9        member into the recess in the liner wall which  
10       will withstand severe lateral loading;

11       Fig. 16a is a schematic representation of a  
12       fifth embodiment of an apparatus in accordance  
13       with the first aspect of the present invention,  
14       incorporating a tubular member with an  
15       extension of a temporary liner to be set across  
16       a washed-out section of a borehole below a  
17       casing shoe;

18       Fig. 16b is a detailed schematic representation  
19       of a portion of the representation of Fig. 16a  
20       again showing the plastic deformation of the  
21       tubular member into the recess in the liner  
22       wall;

23       Fig. 17 is a first example of a method of  
24       conveyance for an apparatus in accordance with  
25       the first aspect of the present invention,  
26       utilising wireline and possibly containing  
27       downhole telemetry for control of the pressure  
28       and flow sensors and logic control of the  
29       hydraulics, and this equipment may also contain  
30       a fluid reservoir which feeds the pump and  
31       generates the pressure;



1        Fig. 18 is a second example of a method of  
2        conveyance for an apparatus in accordance with  
3        the first aspect of the present invention,  
4        utilising drill pipe or coil tubing, and in  
5        this example, the pressure and flow may be  
6        applied and monitored from surface of the  
7        borehole;

8        Fig. 19 is a schematic representation of a  
9        sixth embodiment of an apparatus in accordance  
10       with the first aspect of the present invention,  
11       incorporating a liner section constructed from  
12       a malleable material which is capable of a high  
13       degree of plastic expansion;

14       Fig. 20 is a schematic representation of the  
15       embodiment of Fig. 19, wherein the liner has  
16       been expanded and forms a barrier, akin to a  
17       mud cake, within an open hole section of the  
18       borehole, and which is possibly pinned in  
19       place;

20       Fig. 21 is a schematic representation of a  
21       first embodiment of a tubular member such as a  
22       casing or liner string which has been cut  
23       downhole and which will have a "tie back"  
24       operation performed on it in accordance with a  
25       second aspect of the present invention;

26       Fig. 22 is a schematic representation of a  
27       swage overshot apparatus in accordance with the  
28       second aspect of the present invention being  
29       lowered over the upper end of the tubular  
30       member of Fig. 21;

31       Fig. 23 is a schematic representation of a  
32       packer in accordance with the second aspect of

1       the present invention being lowered into  
2       position within the swage overshot apparatus of  
3       Fig. 22;  
4       Fig. 24 is a more detailed schematic  
5       representation of the packer of Fig. 23 being  
6       actuated within the swage overshot apparatus;  
7       Fig. 25 is schematic representation of the  
8       packer of Fig. 24 after actuation and after the  
9       tubular member has been swaged into formations  
10      provided within the swage overshot apparatus;  
11      Fig. 26 is a schematic representation of the  
12      tubular member of Fig. 25 after the packer has  
13      been removed therefrom;  
14      Fig. 27 is a more detailed longitudinal cross-  
15      sectional view of the packer of Fig. 23 prior  
16      to actuation in the running in hole  
17      configuration and within a tubular member;  
18      Fig. 28 is a further longitudinal cross-  
19      sectional view of the packer of Fig. 27 prior  
20      to actuation in the running in hole  
21      configuration;  
22      Fig. 29 is a longitudinal cross-sectional view  
23      of a very similar packer to the packer of Fig.  
24      28 after actuation in a setting configuration;  
25      Fig. 30 is a part longitudinal cross-sectional  
26      view of the seal assembly and the inner element  
27      of the packer of Fig. 29 in running position;  
28      Fig. 31 is a part longitudinal cross-sectional  
29      view of the seal assembly and the inner element  
30      of the packer of Fig. 29 in setting position;

1           Fig. 32 is a perspective view of the support  
2           ring for the seal assembly of the packer of  
3           Fig. 29; and  
4           Fig. 33 shows fingers of the support ring in  
5           detail, where

6                 Fig. 33a shows a first finger type seen  
7           from the side;

8                 Fig. 33b shows a second finger type from  
9           the side; and

10                Fig. 33c shows the second finger type of  
11           Fig. 33b from above.

12  
13           Fig. 1 shows an apparatus in accordance with the  
14           present invention, and which can be used to provide  
15           a method in accordance with the first and sixth  
16           aspects of the present invention. The apparatus is  
17           generally designated at 1.

18  
19           The apparatus 1 comprises a body 5 which is run into  
20           a casing, liner or tubing 7 or a borehole (not  
21           shown) by means of wireline (not shown in Fig. 1 but  
22           see Fig. 17), coiled tubing (not shown) or drill  
23           pipe (not shown in Fig. 1 but see Fig. 18), or some  
24           other suitable conveyance means, and which is  
25           attached to the body 5 at the upper end 5t thereof.  
26           The body 5 is generally tubular in shape, and  
27           preferably comprises hydraulic logic to control the  
28           setting sequence.

29  
30           A liner patch 9 or tubular member 9 (hereinafter  
31           referred to as tubular member 9) is shown in Fig. 1.  
32           The tubular member 9 is a cylinder, and is arranged

1 co-axially about the body 5. The tubular member 9 is  
2 secured, at its upper 9U and lower 9L ends, to the  
3 body 5 by any suitable means, such as hydraulically  
4 actuated centralising pins 11. The apparatus 1 also  
5 comprises a pair of seal members 13, which are in  
6 the form of packer elements 13, and which are  
7 typically arranged axially inwards of the pins 11  
8 and steel back up segments that prevent extrusion of  
9 the seal packer elements 13. Preferably, the seal  
10 packer elements 13 are those 116 or 214, 215  
11 described subsequently in relation to Figs. 27 to  
12 31. In this manner, the apparatus 1 comprises a  
13 chamber 15 which is defined in volume by the inner  
14 surfaces of the packer elements 13, the inner  
15 circumference of the tubular member 9, and the outer  
16 surface of the body 5. The chamber 15, as shown in  
17 Fig. 1, is sealed by the packer elements 13 with  
18 respect to the environment outside of the chamber  
19 15.

20  
21 A port 17 is formed in the side wall of the body 5,  
22 such that the inner bore of the body 5 is in fluid  
23 communication with the chamber 15. The body 5 also  
24 constrains the opposing hydraulic forces between the  
25 seals 13 when pressure is applied in the chamber 15.

26  
27 In one embodiment of the invention, the apparatus 1  
28 can be run into a liner or borehole on coiled tubing  
29 or drill pipe and in this case, the port 17 is in  
30 fluid communication with the interior of the coiled  
31 tubing or drill pipe respectively.

32

1     However, in another embodiment of the invention, the  
2     apparatus 1 can be run into the liner or borehole on  
3     wireline, and in this embodiment, the port 17 is in  
4     fluid communication with a motor pump and fluid  
5     reservoir tool which is also run into the liner or  
6     borehole with the apparatus, details of which will  
7     be described subsequently.

8  
9     Alternatively, in a yet further embodiment, only one  
10    upper seal assembly 13 may be provided if the lower  
11    end of the liner patch/tubular member 9 were closed  
12    or somehow else sealed.

13  
14    A method in accordance with the present invention  
15    will now be described.

16  
17    The apparatus 1 is conveyed into the liner or  
18    borehole by any suitable means, such as wireline,  
19    coiled tubing or drill pipe until it reaches the  
20    location within the liner or borehole at which  
21    operation of the apparatus is intended. This  
22    location is shown in Fig. 2 as being a location  
23    within the liner 7 or borehole at which there is  
24    either damage to the liner 7, shown at 19, or where  
25    apertures 19 in the liner 7 require to be obturated.  
26    At this point, isolation seals are actuated from  
27    surface (in the situation where drill pipe or coiled  
28    tubing is being used) to allow hydraulic fluid to be  
29    pumped under pressure down the bore of the coiled  
30    tubing or drill pipe, such that the hydraulic fluid  
31    flows through the port 17 into the chamber 15. In  
32    the case where wireline is being used to convey the

1 apparatus 1 into the borehole, the pump motor is  
2 operated to pump hydraulic fluid from the fluid  
3 reservoir into the chamber 15 through the port 17.  
4 This causes the packer elements 13 to move outwardly  
5 to seal against the inner circumference of the ends  
6 9U, 9L of the tubular member 9. Hence, a high  
7 pressure seal is formed between the packer elements  
8 13 and the tubular member 9. The pressure between  
9 the packer element seals 13, and hence within the  
10 chamber 15, continues to increase, such that the  
11 tubular member 9 initially experiences elastic  
12 expansion, and then plastic expansion, in an  
13 outwards direction which is shown in Fig. 3 and in  
14 the graph of Fig. 4. The tubular member 9 expands  
15 beyond its yield point, undergoing plastic  
16 deformation and this is shown in the graph of Fig.  
17 6, until the tubular member 9 forces against the  
18 inner surface of the liner 7, as shown in Fig. 5.  
19 The packer elements 13, and associated steel back-up  
20 rings (not shown) also continue to move outwardly,  
21 such that the chamber 15 is sealed. If desired, the  
22 pressure of fluid within the chamber 15 can be bled  
23 off at this point.

24  
25 Alternatively, the increase of pressure within  
26 chamber 15 can be maintained, such that the tubular  
27 member 9 continues to move outwardly against the  
28 liner 7, such that the liner 7 starts to experience  
29 elastic expansion, and this situation is shown in  
30 Fig. 7 and in the graph of Fig. 8. As will be  
31 understood, as the tubular member 9 makes contact  
32 with the liner wall 7, the pressure increases due to

1 the resistance of the liner wall 7 until the liner  
2 wall 7 undergoes elastic deformation, typically in  
3 the region of up to half a percent. The pressure  
4 can be increased up to the desired level, which may  
5 be many thousand psi. The increase in the pump  
6 volume and setting pressure of fluid can be  
7 continued until a desired level of plastic expansion  
8 of the tubular member 9 has occurred, and with the  
9 liner 7 having only undergone elastic expansion,  
10 when the pressure of the fluid is reduced, the liner  
11 7 will maintain a compressive force inwardly upon  
12 the plastically expanded tubular member 9, and this  
13 situation is shown in Fig. 7 and in the graph shown  
14 in Fig. 8. Hence, with the liner 7 having undergone  
15 elastic deformation, the pressure is released on the  
16 seals (in the form of the packer elements 13, and  
17 associated steel back-up rings) and the locating  
18 pins 11 will automatically withdraw. The tubular  
19 member 9 is securely held since it has undergone  
20 plastic deformation and the liner 7 remaining in  
21 elastic deformation. The liner 7 undergoes plastic  
22 deformation to typically 80% of it's yield  
23 (approximately up to 0.4% elastic expansion).

24  
25 Optionally, the liner wall 7 could be yielded to 1%  
26 plastic expansion and this is shown in Figs. 9 and  
27 10.

28  
29 Hydraulic logic and associated valves and switching  
30 arrangements are provided within the pressure system  
31 located within the body 5, and the logic is arranged

1 such that when the pressure is released, the pins 11  
2 are released.

3  
4 The releasing of the pressure of the fluid causes  
5 the hydraulically actuated centralising pins 11 to  
6 retract radially inward into the body 5, and this  
7 also causes the packer elements 13 to retract  
8 radially inward toward the body 5, such that the  
9 seal between the body 5 and tubular member 9 is  
10 released, and the body 5 is free from engagement  
11 with the tubular member 9. The body 5 can then be  
12 withdrawn upwards from the borehole, and as shown in  
13 Fig. 11, the tubular member is held in compression  
14 by the force of the elastic compression of the  
15 tubing 7 across the full length and circumference of  
16 the tubular member 9.

17  
18 The arrangement of double packer elements 13 is most  
19 suitable for relatively short length of tubular  
20 members 9 in the region of up to a few meters in  
21 length. This relatively short length tubular member  
22 9 is suitable for use in water shut-off across  
23 perforations or tubing leaks, and repairing damaged  
24 casing or liner tubing 7.

25  
26 In order to reduce the hoop strain experienced by  
27 the very ends of the tubular member 9 or liner patch  
28 9, and in order to ensure that the full length of  
29 the liner patch 9 is fully expanded, it is  
30 preferable to cut longitudinally arranged slots (not  
31 shown) spaced apart about the circumference of the  
32 very end of the liner patch 9.



1  
2 An alternative embodiment of the invention is shown  
3 in Fig. 12 and provides a variable length extrudable  
4 tubular member 9. As shown in Fig. 12, the tubular  
5 member 9 is of any suitable length. The embodiment  
6 of Fig. 12 comprises an upper body section 21, and a  
7 lower body section 23, both of which comprise  
8 hydraulically actuated centraliser pins 11 and  
9 sealing members 13 in the form of packer elements  
10 13, as with the first embodiment of the apparatus 1.  
11 The port 17 is carried on the upper body section 21,  
12 and the second embodiment is operated in a similar  
13 manner to the first embodiment 1. However, slips 50  
14 are provided on the upper body section 21, and act  
15 between the upper body section 21 and the inner  
16 surface of the upper end of the extrudable tubular  
17 member 9 in order to ensure that there is no  
18 unwanted slippage therebetween when the pressure  
19 within the chamber 15 increases. Internal dogs,  
20 inwardly projecting keys, or another suitable  
21 arrangement (generally designated at 52) are  
22 provided on the inner surface of the lower in use  
23 end of the tubular member 9 and which act to stop  
24 the lower body section 23 from bursting out of the  
25 lower end of the lower body section 23 when the  
26 pressure within the chamber 15 increases. The lower  
27 body section 23 can be retrieved from the interior  
28 of the tubular member 9 after the tubular member 9  
29 has been expanded, for instance by a fishing  
30 operation, or the lower body section 23 can be  
31 pumped out of the lower end of the tubular member 9.  
32

1 A third embodiment of an apparatus in accordance  
2 with the present invention is shown in Fig. 13 as  
3 comprising a body 5 with upper and lower packer  
4 elements 13 and upper and lower sets of  
5 hydraulically actuated centralising pins 11. The  
6 body also carries a port 17 located between the two  
7 packer elements 13 and is operated in a similar  
8 manner to the apparatus 1. However, the tubular  
9 member 9 is integrally formed with a seal assy 25 at  
10 its lower end, which can be used as a tubing  
11 receptacle and seal assembly. It should be noted in  
12 Fig. 13 that the liner 7 has been pre-formed with a  
13 bank of recesses 27 which are axially spaced along a  
14 short length of the interior surface of the liner 7.  
15 In the examples shown in Fig. 13, there are four  
16 recesses 27, but any suitable number of recesses 27  
17 can be provided. Alternatively, no recesses need be  
18 provided and in this scenario the tubular member 9  
19 is expanded until the liner 7 or casing 7  
20 plastically expands in order to ensure a high  
21 quality metal to metal seal is created.

22  
23 Where recesses are provided, as seen most clearly in  
24 Fig. 14b, the tubular member 9 will expand into the  
25 recesses 27, and the engagement there between will  
26 provide the tubular member 9 with a much higher  
27 resistance to lateral movement through the liner.  
28 In the example given in Fig. 14a, the tubular member  
29 9 is used to set the tubing receptacle and seal  
30 assembly (also known as a seal bore receptacle)  
31 within the liner 7.

32

1 As shown in Figs. 15a and 15b, the lower end of the  
2 tubular member 9 is secured to a nipple profile 29,  
3 and hence can be used to set the nipple profile 29  
4 within the liner 7.

5  
6 A further alternative embodiment of the invention is  
7 shown in Fig. 16a, and Fig. 16b, where the lower end  
8 of the tubular member 9 is secured to a temporary  
9 liner section 31. In this example, the temporary  
10 liner section 31 is set across a washed-out section  
11 below the casing shoe at the very end of the liner  
12 7.

13  
14 As previously described, the apparatus 1 can be  
15 conveyed into the borehole by means of drill pipe 33  
16 or coiled tubing with pressure controlled from the  
17 surface, and in this example, the drill pipe 33 is  
18 shown in Fig. 18.

19  
20 Alternatively, the apparatus 1 can be conveyed into  
21 the borehole by means of wireline 35, and in this  
22 example, the apparatus 1 is coupled to the lower end  
23 of a sensor tool 37 which can be used to indicate  
24 the pressure of fluid being pumped into and through  
25 the port 17. The upper end of the sensor tool 37 is  
26 coupled to the lower end of a motor pump and  
27 hydraulic fluid reservoir 39, the upper end of which  
28 is coupled to the lower end of telemetry tool 41  
29 which can be used to indicate the position of this  
30 bottom hole assembly to the operator at the surface.

31

1 Fig. 19 shows a further embodiment of an apparatus  
2 in accordance with the present invention. This  
3 embodiment of the invention provides a variable, and  
4 in this example, extended length liner in the form  
5 of an extrudable tubular member 9. As shown in Fig.  
6 19, the tubular member 9 is of any suitable length.  
7 The embodiment of Fig. 19 comprises an upper body  
8 section 21, and a lower body section 23, both of  
9 which comprise hydraulically actuated centraliser  
10 pins 11 and sealing members 13 in the form of packer  
11 elements 13, as with the first embodiment of the  
12 apparatus 1. The port 17 is carried on the upper  
13 body section 21, and the embodiment of Fig. 19 is  
14 operated in a similar manner to the first embodiment  
15 1. However, slips 50 are provided on the upper body  
16 section 21, and act between the upper body section  
17 21 and the inner surface of the upper end of the  
18 extrudable tubular member 9 in order to ensure that  
19 there is no unwanted slippage therebetween when the  
20 pressure within the chamber 15 increases. Internal  
21 dogs, inwardly projecting keys, or another suitable  
22 arrangement (generally designated at 52) are  
23 provided on the inner surface of the lower in use  
24 end of the tubular member 9 and which act to stop  
25 the lower body section 23 from bursting out of the  
26 lower end of the lower body section 23 when the  
27 pressure within the chamber 15 increases. The lower  
28 body section 23 can be retrieved from the interior  
29 of the tubular member 9 after the tubular member 9  
30 has been expanded, for instance by a fishing  
31 operation, or the lower body section 23 can be  
32 pumped out of the lower end of the tubular member 9.

1     The pressure within the chamber 15 is increased as  
2     before, such that the tubular member 9 expands to  
3     meet the inner surface of the open hole section of  
4     the borehole, which may be a greater diameter than  
5     the drill bit diameter, as shown in Fig. 20. Pins  
6     55 may optionally be provided as shown in Figs. 19  
7     and 20, through the side wall of the tubular member  
8     9 (with a suitable sealing arrangement  
9     therebetween), such that the pins are forced into  
10    the formation to enhance the grip between the  
11    formation and the tubular member 9. The pins 55 (if  
12    present) are preferably run into the borehole, such  
13    that they are projecting inwardly from the tubular  
14    member, so that no obstruction is provided by the  
15    pins 55, on the outer surface of the tubular member  
16    9, when the apparatus is being run into the  
17    borehole. The tubular member 9 of Figs. 19 and 20  
18    is preferably formed from a relatively highly  
19    malleable, and thus relatively highly extrudable,  
20    metal, such that it can undergo a relatively large  
21    degree of plastic deformation without rupturing.  
22    Additionally during the setting sequence of the  
23    tubular member 9, the hydrostatic pressure within  
24    the borehole, which to a large extent is created by  
25    the amount of fluids which have been introduced into  
26    the borehole from surface, may be reduced (by  
27    withdrawing a volume of these fluids from the  
28    borehole) so that when the tubular member 9 is  
29    expanded and the pressure taken off, there is a  
30    pressure overbalance between the inside of the  
31    borehole and the formation pressure. This pressure

1     overbalance will yet further assist holding the  
2     tubular member 9 in place.

3  
4     Therefore, it can be seen that the apparatus 1 can  
5     be provided with an uninterrupted central mandrel  
6     section which couples to both the upper and lower  
7     ends of the tubular member 9, such as the one piece  
8     body section 5 of the first embodiment shown in Fig.  
9     1, or can be provided with split upper 21 and lower  
10    23 body sections which are respectively coupled to  
11    the upper and lower ends of the tubular member 9,  
12    such as the embodiment shown in Fig. 12. In the  
13    latter scenario, the opposing forces on the seals 13  
14    are contained by, for instance slips (as indicated  
15    for the top seal 13), or a no go (as indicated for  
16    the bottom seal 13). Also, the length of the  
17    tubular member 9 is variable, depending upon  
18    conveyance technique, well geometry etc.

19  
20    The expansion of the tubular member 9 against the  
21    inner surface of the liner 7 may provide a high  
22    integrity hydraulic fluid and/or gas seal  
23    therebetween, and this will particularly be the case  
24    when the tubular member 9 is expanded into recesses  
25    27. However, the high integrity seal can be further  
26    aided by the provision of one or more elastomeric  
27    bands or rings around the outer circumference of the  
28    tubular member 9.

29  
30    A first embodiment of a swage casing tie-back system  
31    100 is shown in Figs. 21 to 26 and is in accordance

1 with the second, third and sixth aspects of the  
2 present invention.

3  
4 Fig. 21 shows a borehole 102 having a diameter of 12  
5  $\frac{1}{4}$  inches which has been previously lined with a  
6  $9\frac{7}{8}$  inch diameter casing string 104. However, it  
7 should be noted that the embodiments described below  
8 can be used with differently sized boreholes 102  
9 and/or casing strings 104. Normally, as those  
10 skilled in the art will realise, the casing string  
11 104 extends all the way up to the surface. However,  
12 in this case, the upper portion of the casing string  
13 (not shown) has been cut away from the lower portion  
14 of the casing string 104 and has been removed from  
15 the borehole 102. In some circumstances, casing  
16 strings can be backed off but in circumstances where  
17 the casing string failed to back-off, the swage  
18 casing tie-back system 100 would be utilised.

19  
20 Fig. 22 shows that a tie-back casing string 106 has  
21 been run into the borehole 102, the casing string  
22 106 having a swage overshot device 108 mounted at  
23 its lower end. The swage overshot device 108 is  
24 formed from a relatively tough material such as P110  
25 grade steel and comprises a number (such as three as  
26 shown in Fig. 22) of internal recesses 110 or  
27 profiles formed on its inner bore. The rest of the  
28 internal bore of the overshot device 108 has a  
29 diameter just slightly larger than the outer  
30 diameter of the casing string 104 such that the  
31 overshot device 108 slips over the upper end of the  
32 casing string 104 like a sleeve.

1  
2 Fig. 23 shows the next sequence of events where a  
3 body member comprising a packer tool 112 is run on  
4 the lower end of a string of drillpipe 114, down  
5 through the upper casing string 106 until the packer  
6 tool 112 is aligned with the annular recesses 110 of  
7 the overshot device 108. The packer tool 112  
8 comprises a pair of seal elements 116 which are  
9 preferably longitudinally spaced apart by a distance  
10 which is slightly greater than the longitudinal  
11 distance between the uppermost annular recess 110  
12 and the lowermost annular recess 110. An  
13 arrangement of apertures 118 which extend all the  
14 way through the side wall of the overshot device 108  
15 are provided between the longitudinally spaced apart  
16 pair of seal elements 116.

17  
18 Fig. 24 shows that the seal elements 116 have been  
19 actuated to form a seal between the outer surface of  
20 the packer tool 112 and the inner surface of the  
21 casing string 104 such that the annular region or  
22 chamber between the pair of seal elements 116 is  
23 sealed with respect to the annular region outside of  
24 the pair of seal elements 116. Fig. 24 also shows  
25 that water is pumped through the throughbore of the  
26 drillstring 114, into the interconnecting bore of  
27 the packer tool 112 and through the apertures 118  
28 and into the annular region or chamber between the  
29 pair of seal elements 116. The water is continued  
30 to be pumped into the aforesaid chamber until the  
31 pressure reaches the desired level such as up to or  
32 perhaps even greater than 30,000psi. As this



1 hydraulic pressure increases, the force provided by  
2 it moves or swages the casing string 104 into the  
3 annular recesses 110 as shown in Fig. 25.  
4 Accordingly, the casing string 104 is now tied back  
5 to the casing string 106.

6  
7 The pair of sealing elements 116 are then de-  
8 activated and the drillpipe string 114 and thus the  
9 packer tool 112 are removed from the casing strings  
10 104, 106.

11  
12 Thus, as shown in Fig. 26, the casing 104 is  
13 permanently expanded into the internal profile or  
14 recesses 110 of the overshot device 108 by firstly  
15 elastic deformation and secondly plastic deformation  
16 thus achieving a mechanical and pressure tight  
17 joint. Indeed, after the retrieval of the drillpipe  
18 114 and the packer tool 112, the resulting joint has  
19 comparable mechanical integrity to the original  
20 casing string 104 and makes no reduction in internal  
21 diameter. Furthermore, the resulting joint provided  
22 is a metal to metal seal.

23  
24 It should also be noted that the casing strings 104,  
25 106 could be a string of liner tubings or production  
26 tubings or the like.

27  
28 Fig. 27 shows a first embodiment of a packer tool  
29 112 in accordance with both the second and the third  
30 aspects of the present invention, although the lower  
31 end of the drillpipe string 114 is omitted for  
32 clarity purposes. It should be noted that the

1 packer tool 112 is broadly the same as the packer  
2 tool 210 of Figs. 28 and 29, although the skilled  
3 reader will realise that the pair of wedge members  
4 122 of the packer 112 are arranged in the opposite  
5 direction to the pair of wedge members 222 of the  
6 packer 210. However, this does not effect the  
7 operation of the packer tool 112 compared with the  
8 packer 210. Accordingly, only the packer 210 will  
9 be described in detail.

10

11 Fig. 28 shows a packer tool 210 in accordance with  
12 the second, third, fifth and sixth aspects of the  
13 present invention disposed in an annular space, such  
14 as a production tube 211, and can be modified to  
15 provide the spaced apart seals of the embodiments  
16 of the first aspect of the invention. The packer  
17 210 comprises a first, upper, inner element 212  
18 which acts as a piston, a second, lower, inner  
19 element 213 which also acts as a piston, a first  
20 seal assembly 214 and a second seal assembly 215,  
21 which will be described in detail further below.  
22 The two inner elements 212, 213 are telescopically  
23 coupled together by means of a mandrel 217. An  
24 annular sleeve 218 is disposed between the packer  
25 210 and the production tube 211 in the longitudinal  
26 direction between the two seal assemblies 214 and  
27 215. The annular sleeve 218 provides the sealing  
28 surface towards the production tube 211.

29

30 The inner, upper, element 212 will now be described  
31 with reference to Fig. 30. The inner element 212 is  
32 generally cylindrical and comprises moveable

1 connection means in both ends for telescopic  
2 coupling to the mandrel 217 and other equipment,  
3 such as pipes, controlling means etc. respectively.  
4 In addition, the inner element 212 comprises a wedge  
5 member 222.

6  
7 The seal assembly 214 (see Fig. 28) is slidable  
8 disposed on the outside of the inner element 212,  
9 and comprises an upper support sleeve 220, a lower  
10 support sleeve 221 and a seal 223. The seal 223  
11 comprise an annular expandable ring, preferably made  
12 of expandable and temperature resistant materials.

13  
14 Between the seal assembly 214 and the inner element  
15 212 there are disposed displacement means 219 (shown  
16 in Figs. 30 and 31. The displacement means 219  
17 operates the sliding of the seal assembly 214  
18 relative to the inner element 212. In this  
19 embodiment the displacement means is a hydraulic  
20 drive, and Figs. 30 and 31 show upper hydraulic  
21 fluid chambers 219au and lower hydraulic fluid  
22 chambers 219al which are selectively pressurised  
23 with respective hydraulic fluid delivered from  
24 surface via hydraulic lines (not shown). For  
25 instance, in order to actuate the seal assembly,  
26 pressurised fluid is forced into chamber 219al which  
27 forces the inner element 212 downwards from the  
28 position shown in Fig. 30 to the position shown in  
29 Fig. 31 thus forcing the seal 223 to expand outwards  
30 due to the wedge member 222 action upon it.

31

1 The support sleeves 220, 221 form the expandable  
2 parts of the seal assembly together with the seal  
3 223. The support sleeves 220, 221 preferably  
4 comprise fingers of two different types, where every  
5 second finger is of the same type. The fingers are  
6 all connected to an end 230 of the support sleeve.  
7 This is shown in detail in Fig. 32.

8  
9 The first finger type 231 comprises an elongated  
10 member 232. In the end opposite to the end 230 of  
11 the support sleeve 220, the first finger 231  
12 comprises a generally triangular support member 233,  
13 the end surface of which defines a support surface  
14 234.

15  
16 The second finger type 241 comprises an elongated  
17 member 42. In the end opposite to the end 230 of  
18 the support sleeve 220, the second finger 241  
19 comprises a generally triangular support member 243.  
20 The support member 243 is differing from the support  
21 member 233 in that it is generally T-shaped seen  
22 from above (Fig. 33c). The end of the support  
23 member 243 defines a support surface 244, and the  
24 other side of the support member 433 defines a  
25 support surface 245. Preferably, the crossbars of  
26 the T-shaped support members 243 of the different  
27 second type fingers 241 are lying next to each other  
28 in the running in hole position.

29  
30 The operation of the packer will now be described  
31 with reference to Figs. 30 and 31.

32

1 Fig. 30 shows the upper part of the packer 210 in  
2 the running in hole position. Here, the annular  
3 seal 223 particularly rests on the support surfaces  
4 244 of the second type fingers 241. The support  
5 surfaces 245 of the second type fingers 241 are  
6 further resting on the support surface 234 of the  
7 first type finger 231. The annular seal 223 is in  
8 the radially inward direction resting on the wedge  
9 member 222 and in the radially outward direction  
10 resting on the annular sleeve 218 (Fig. 28).

11  
12 When the desired position of the packer 210 in the  
13 production tube 211 is found, a compression force is  
14 applied to the packer 210 by means of the  
15 displacement means 219. The compressive force  
16 results in a downwardly directed displacement of the  
17 support sleeve 220 and compression of the support  
18 sleeve 221 in Fig. 30. Consequently, the support  
19 sleeve 221 together with the annular seal 223 climbs  
20 the wedge member 222, which again causes the annular  
21 seal 223 and the fingers 231, 241 of the support  
22 sleeves 220, 221 to expand radially.

23  
24 The expansion of the support sleeves 220, 221 is  
25 shown in Fig. 31. The annular seal 223 is now  
26 expanded to a larger radius, but has substantially  
27 the same shape as the previous form. This is due to  
28 the support sleeves 220, 221. Since the fingers of  
29 the support sleeves 220, 221 have their mutual  
30 distance increased, the crossbars of the T-shaped  
31 support members 243 of the different second type  
32 fingers 241 have their mutual distance increased.

1 The annular seal 223 is now resting on both the  
2 support surfaces 234 of the first type finger 231  
3 and the support surface 244 of the second type  
4 finger 244. Preferably, the support surfaces 245  
5 are also still resting on the support surfaces 234,  
6 even though the contact surface between them has  
7 decreased.

8  
9 Consequently, the annular seal 223 is still  
10 supported in the desired position in a way that  
11 prevents extrusions of the seal 223, even under high  
12 pressure.

13  
14 Accordingly, the expansion of the seal assemblies  
15 214, 215 causes the sleeve 218 to be pressed out  
16 towards the casing or production tube with a large  
17 force, and the seal 223 is now in the setting  
18 position.

19  
20 The operation from the setting position to the  
21 running position is achieved by reducing the  
22 compression force on the displacement means 219, by  
23 means of relieving the pressure in chambers 219al  
24 and increasing the pressure in chambers 219au which  
25 causes the inner element 212 to move upwardly again  
26 to the position shown in Fig. 30. As the annular  
27 seal 223 slides down the wedge member 222 the radius  
28 of the seal 223 will decrease and consequently the  
29 fingers 231, 241 of the sleeves 220, 221 will go  
30 back to their original position.

31

1 In Figs. 33a and 33c the support surfaces 234 and  
2 244 are shown generally perpendicular to their  
3 respective elongated members 232 and 242. These  
4 support surfaces may of course have an angle with  
5 their elongated members.

6

7 It should be noted that the production tube 211  
8 could be a casing string or liner string or the  
9 like.

10

11 All of the embodiments described herein have the  
12 great advantage that they create a metal to metal  
13 seal downhole.

14

15 Modifications and improvements may be made to the  
16 embodiments without departing from the scope of the  
17 invention. For instance, the packer tool 112 and/or  
18 the packer tool 210 of Figs 27 and 28 respectively  
19 could be modified to provide a plug (not shown) in  
20 accordance with a fourth aspect of the present  
21 invention and in this case, embodiments thereof  
22 could comprise a single seal assembly 116 and  
23 214/215 respectively, where the plug could be run on  
24 drill pipe, coil tubing or wireline. Setting of the  
25 plug would be via hydraulic or mechanical means. A  
26 seal setting piston (not shown) would be attached to  
27 a mandrel (not shown) that protrudes through the top  
28 of the single seal assembly of the plug. This  
29 mandrel would be attached to a setting tool, such  
30 that when the mandrel is pulled upwards against a  
31 sleeve (not shown) acting on the top of the seal

1 assembly, the seal is activated and is extruded  
2 outwardly to contact the casing wall, for instance.

3

4 Final setting loads of the plug would vary,  
5 depending on the differential pressure requirements.  
6 These final setting loads could be set via either a  
7 mechanical shear stud (not shown) when set  
8 mechanically or via final hydraulic pressure when  
9 set with hydraulics. The seal setting piston would  
10 be maintained in the set position via locking the  
11 hydraulics in place for a hydraulic set or with  
12 slips or a ratchet mechanism for mechanical sets.

13

14 For retrieval of the plug, the seals would be de-  
15 activated via releasing the hydraulic pressure or by  
16 releasing the ratchet/slip mechanism.

17

18 For high differential pressures, the setting force  
19 would be sufficiently high to swage the casing with  
20 the single seal assembly, thereby key seating the  
21 seal assembly into the well delivering a large  
22 resistance to movement up or down the well.



## 1 CLAIMS:-

2

3 1. An apparatus for securing a tubular member  
4 within a liner or borehole, the apparatus comprising  
5 at least one seal means associated with the tubular  
6 member, and a pressure control means operable to  
7 increase the pressure within the tubular member,  
8 such that operation of the pressure control means  
9 causes the tubular member to move radially outwardly  
10 to bear against the inner surface of the liner or  
11 borehole wall.

12

13 2. Apparatus according to Claim 1, wherein the  
14 apparatus comprises a pair of seal means, and  
15 apparatus is arranged such that the pressure is  
16 increased within the tubular member between the pair  
17 of seal means.

18

19 3. Apparatus according to either of claims 1 or 2,  
20 wherein the tubular member is moved radially  
21 outwardly such that the tubular member undergoes  
22 elastic deformation and also plastic deformation.

23

24 4. Apparatus according to claim 2 or to claim 3  
25 when dependent on claim 2, wherein the apparatus  
26 further comprises a body located co-axially within  
27 the tubular member and the pair of seal means are  
28 mounted upon the body and are selectively energised  
29 to seal against the inner surface of the tubular  
30 member.

31

1     5.    Apparatus according to any preceding claim  
2     wherein one end of the tubular member is provided  
3     with hoop strain reduction means.  
4

5     6.    Apparatus according to any preceding claim,  
6     wherein at least one of the liner and tubular member  
7     is provided with a surface that facilitates  
8     providing engagement between the liner and the  
9     tubular member.  
10

11    7.    A method of securing a tubular member within a  
12    liner or borehole of a well, the method comprising:-  
13         inserting the tubular member into the borehole;  
14         and increasing the pressure within the tubular  
15    member between a pair of seal means associated with  
16    the tubular member, such that the pressure increase  
17    causes the tubular member to move radially outwardly  
18    to bear against the inner surface of the liner or  
19    borehole.  
20

21    8.    A method according to claim 7, further  
22    comprising inserting the tubular member into the  
23    liner or borehole to the required depth by way of  
24    one of wireline, coil tubing and drill pipe.  
25

26    9.    A method according to either of claims 7 or 8,  
27    wherein the tubular member is moved radially  
28    outwardly such that the tubular member undergoes  
29    elastic deformation and also plastic deformation.  
30

31    10.   A method according to any of claims 7 to 9,  
32    wherein at least one of the liner and the tubular

1 member is provided with a surface that facilitates  
2 providing engagement between the liner and the  
3 tubular member.  
4

5 11. A method according to claims 7 to 10, wherein a  
6 metal to metal seal is formed between the outer  
7 circumference of the tubular member and the inner  
8 circumference of the liner.  
9

10 12. An apparatus for securing a first tubular  
11 member to a second tubular member already located  
12 within a liner of borehole of a well, the apparatus  
13 comprising:-

14 a pair of seal means associated with one of the  
15 first and second tubular members;

16 and a pressure control means operable to  
17 increase the pressure within one of the first and  
18 second tubular members between the pair of seal  
19 means;

20 such that operation of the pressure control  
21 means causes one of the first and second tubular  
22 members to move radially to bear against a surface  
23 of the other of the first and second tubular  
24 members;

25 such that at least one of the first and second  
26 tubular members undergo elastic deformation and also  
27 plastic deformation.  
28

29 13. An apparatus according to claim 11, wherein the  
30 pair of seal means are mounted on a body member  
31 which are capable of alignment downhole with one or

1 more profiles formed on a surface of the first  
2 tubular member.

3

4 14. Apparatus according to claim 12, wherein the  
5 pair of seal means are longitudinally spaced apart  
6 on the body member and the pair of seal means are  
7 arranged such that they are spaced further apart  
8 than the longitudinal extent of the one or more  
9 profiles.

10

11 15. Apparatus according to either of claims 13 or  
12 14, wherein the pair of seal means are capable of  
13 actuation to seal against the inner bore of the  
14 second tubular member, and the body member is  
15 provided with one or more fluid ports or apertures  
16 formed in its sidewall, such that a fluid is capable  
17 of being pumped through the first tubular member,  
18 through the one or more fluid ports and into a  
19 chamber defined between the outer surface of the  
20 body member, the inner bore of the first tubular  
21 member and the pair of seal means.

22

23 16. A method of securing a first tubular member to  
24 a second tubular member already located within a  
25 liner or borehole of a well, the method comprising:-  
26 inserting the first tubular member into the  
27 borehole such that a lower end thereof is in close  
28 proximity with an upper end of the second tubular  
29 member; and  
30 increasing the pressure within one of the first and  
31 second tubular members between a pair of seal means  
32 associated with one of the first and second tubular

1 members, such that the pressure increase causes one  
2 of the first and second tubular members to move  
3 radially to bear against a surface of the other of  
4 the first and second tubular members, wherein at  
5 least one of the first and second tubular members  
6 undergo elastic deformation and also plastic  
7 deformation.

8

9 17. A method according to claim 16, wherein the  
10 pair of seal means are mounted on a body member  
11 which is lowered into the wellbore through the first  
12 tubular member by an elongate member and is further  
13 lowered into the second tubular member.

14

15 18. A method according to either of claims 16 or  
16 17, wherein the pair of seal means are  
17 longitudinally spaced apart on the body member and  
18 the pair of seal means are arranged such that they  
19 are spaced further apart than the longitudinal  
20 extent of the one or more profiles, and the body  
21 member is lowered into the first tubular member  
22 until the pair of seal means straddle the one or  
23 more profiles.

24

25 19. A method according to any of claims 16 to 18,  
26 wherein the pair of seal means are actuated to seal  
27 against the inner bore of the second tubular member.

28

29 20. A method according to any of claims 16 to 19,  
30 wherein a fluid is used to provide the pressure and  
31 the fluid is pumped through the first tubular  
32 member, through one or more fluid ports provided in

1 a sidewall of the body member and into a chamber  
2 defined between the outer surface of the body  
3 member, the inner bore of the first tubular member  
4 and the pair of seal means.

5  
6 21. A method according to claim 22, wherein once  
7 the pressure has increased to a sufficient level,  
8 one or more circumferential portions of the first  
9 tubular member are expanded into a respective number  
10 of the one or more profiles of the second tubular  
11 member to form a joint between the first tubular  
12 member and the second tubular member.

13  
14 22. A sealing device for use in an annular space,  
15 where the sealing device comprises:-

16 at least one substantially cylindrical inner  
17 element;

18 at least one seal assembly; and

19 a displacement means operable to apply a force  
20 on the said seal assembly;

21 where the said inner element comprises a wedge  
22 member, and the said seal assembly is slidable over  
23 the wedge member along the longitudinal direction of  
24 the inner element, wherein the said seal assembly  
25 expands radially outward when forced over the wedge  
26 member;

27 the seal assembly comprising a radially  
28 expandable annular seal supported by at least one  
29 radially expandable support sleeve;

30 characterised in that the support sleeve forms  
31 a substantially continuous support surface towards

1 the said annular seal in both expanded and non-  
2 expanded positions.

3

4 23. A sealing device according to claim 22, wherein  
5 the support sleeve comprises fingers supporting the  
6 said annular seal.

7

8 24. A sealing device according to claim 23, wherein  
9 the support sleeve comprises at least two types of  
10 fingers.

11

12 25. A sealing device according to any of claims 22  
13 to 24, wherein the sealing device comprises two  
14 radially expandable support sleeves.

15

16 26. A sealing device according to any of claims 23  
17 to 25, wherein the displacement means is disposed  
18 between the said inner element and the said seal  
19 assembly and the fingers are connected to an end of  
20 their respective support sleeve.

21

22 27. A sealing device according to claim 24, wherein  
23 the first type of finger comprises a generally  
24 triangular support member, the end surface of which  
25 defines a support surface and the second type of  
26 finger preferably comprises a generally triangular  
27 support member being generally T-shaped seen from  
28 above, the end of which defines a support surface,  
29 where the other side of the support member defines a  
30 support surface.

31

1     28. A sealing device according to claim 27, wherein  
2     every second finger of the support sleeve is of the  
3     first type of finger, or the second type of finger  
4     respectively.

5  
6     29. A sealing device according to claim 28, wherein  
7     the support surfaces of the second type of fingers  
8     in a running in hole position rest on at least some  
9     of the support surfaces of the first type of  
10    fingers.

11  
12    30. A sealing device according to any of claims 22  
13    to 29, wherein there are at least two sealing  
14    devices connected by means of a mandrel.

15  
16    31. A sealing device according to any of claims 22  
17    to 30, wherein an isolation plug is provided which  
18    comprises one sealing device which is run into a  
19    downhole well on an elongate member.

20  
21    32. An isolation plug for plugging a downhole  
22    tubular, the isolation plug comprising a sealing  
23    device according to any of claims 22 to 31 and a  
24    seal actuation mechanism, the seal actuation  
25    mechanism being operable to expand the annular seal  
26    radially outwards toward the downhole tubular to  
27    firstly seal against an inner bore thereof and  
28    secondly elastically and furthermore plastically  
29    deform the downhole tubular.

30  
31    33. An isolation plug according to claim 32,  
32    wherein a seal setting piston is attached to a



1 mandrel which protrudes through an upper end of the  
2 isolation plug and the mandrel is attached to a  
3 setting tool, such that when, in use, the mandrel is  
4 pulled upwards against a sleeve mounted against the  
5 upper end of the isolation plug, the seal means is  
6 activated and is extruded outwardly to contact the  
7 downhole tubular.

8  
9 34. A method of plugging a downhole tubular  
10 comprising inserting an isolation plug into the  
11 downhole tubular to a desired location and expanding  
12 a seal means of the isolation plug in a radially  
13 outwards direction toward the downhole tubular by  
14 operating a seal actuation mechanism of the  
15 isolation plug such that the seal means firstly  
16 seals against an inner bore of the downhole tubular  
17 and secondly elastically and furthermore plastically  
18 deforms the downhole tubular.

19  
20 35. A method of providing a downhole metal to metal  
21 seal between two concentrically arranged tubulars,  
22 comprising the steps of:-

23  
24 a) expanding radially outwardly the innermost  
25 tubular through elastic and then plastic deformation  
26 until it contacts the inner bore of the second  
27 tubular; and

28  
29 b) continued expansion of the first tubular such  
30 that it firstly elastically and secondly plastically  
31 expands the second tubular radially outwardly.



INVESTOR IN PEOPLE

Application No: GB0403082.1

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Examiner: Mr Rob Lynch

Claims searched: 1-21

Date of search: 6 May 2004

**Patents Act 1977: Search Report under Section 17****Documents considered to be relevant:**

Category	Relevant to claims	Identity of document and passage or figure of particular reference
X	1 - 4, 7 - 10, 12, 13, 16, 17, 19, 20 & 21	EP 0937861 A3 (Halliburton Energy Services, Inc.) See whole document, especially figure 3 and paragraphs 38 & 39, noting liner 122, and seal means 202 & 204
X,E	1, 2, 4, 6 - 8, 10 & 11	WO 2004/015241 A1 (Baker Hughes Incorporated) See whole document, especially abstract and figures, noting especially seals 36, 38, and expanding tubular section 52.
X	1, 2, 4, 6 - 8 & 10	EP1165933 A1 (G.E.I.E. EMC) See abstract, figures and lines 22 - 34 of column 3 noting especially seals 11
X	1, 2, 4, 6 - 8 & 10	US2002/0020524 A1 (Halliburton Energy Services, Inc.) See figures and paragraphs 5 - 11, noting seals 131

**Categories:**

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.

**Field of Search:**Search of GB, EP, WO & US patent documents classified in the following areas of the UKC<sup>W</sup> :

E1F

Worldwide search of patent documents classified in the following areas of the IPC<sup>07</sup>

E21B

The following online and other databases have been used in the preparation of this search report

Online: EPODOC, WPI, PAJ, OPTICS